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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS
MIKE GLEASON – CHAIRMAN
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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

UNS Gas, Inc. ("UNS Gas" or "Company"), through undersigned counsel, hereby files the Rebuttal Testimony of James S. Pignatelli, David G. Hutchens, Kentton C. Grant, Dallas J. Dukes, Karen G. Kissinger, Gary A. Smith, D. Bentley Erdwurm and Denise A. Smith in the above-captioned docket.

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Arizona Corporation Commission
DOCKETED

MAR 16 2007

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RESPECTFULLY SUBMITTED this 16th day of March 2007.

UNS Gas, Inc.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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UNS GAS, INC.

REBUTTAL TESTIMONY

March 16, 2007

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
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Rebuttal Testimony of

James S. Pignatelli

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is James S. Pignatelli. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same James S. Pignatelli that filed Direct Testimony in this case?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my testimony is to provide a general response to the Direct Testimony filed by the intervenors and specifically to the Direct Testimony filed on behalf of Commission Staff and the Residential Utility Consumer Office ("RUCO"). UNS Gas, Inc. ("UNS Gas") disagrees with several of the rate base and operating income adjustments Staff and/or RUCO recommended. Specifically, I take issue with the recommendations to exclude construction work in progress ("CWIP") from rate base. Also, UNS Gas does not agree that either Staff's or RUCO's cost of capital and rate of return recommendations is fair or reasonable. In light of the Arizona Court of Appeals decision regarding Chaparral City Water Company, UNS Gas is now recommending that the cost of capital be applied to the Company's fair value rate base. In addition, I summarize some of the differences the Company has with certain observations and recommendations the intervenors make about the Company's Demand Side Management ("DSM") programs, UNS Gas' purchased gas adjustor ("PGA"), and gas procurement practices. Further, UNS Gas strongly disagrees with Staff's and RUCO's rate design proposals. First, their rate design does not move UNS Gas sufficiently close to cost-based rates. Second, Staff's and RUCO's proposals will continue the subsidies from cold-weather climate customers – including low-income cold-weather climate customers

– to warm-weather climate customers. Finally, UNS Gas has provided substantial evidence to justify approval of its proposed Throughput Adjustment Mechanism ("TAM") that decouples the Company's dependence on natural gas consumption to meet its revenue requirement and allows it the opportunity to earn its authorized rate of return.

II. RATE BASE AND OPERATING INCOME ADJUSTMENTS.

Q. What is UNS Gas' general reaction to Staff's and RUCO's proposed adjustments?

A. I will provide general comments to some of the adjustments Staff and/or RUCO propose.

1. Construction Work in Progress ("CWIP").

Mr. Kentton C. Grant for UNS Gas specifically rebuts both Staff's and RUCO's recommendations to exclude CWIP from rate base. Including CWIP in rate base will help the Company maintain its financial integrity and UNS Gas provides ample evidence justifying its inclusion. There is no requirement that "extraordinary circumstances" must be shown to justify CWIP inclusion. Even so, Mr. Grant clearly explains how growth is causing UNS Gas to raise substantial sums of additional capital to fund the necessary plant investments to service that growth. Further, because natural gas prices are so volatile, UNS Gas is exposed to large gas deferral balances and customers using less natural gas. I have seen no evidence from Staff or RUCO rebutting the Company's evidence that growth causes these adverse impacts, and that regulatory lag is causing a net adverse impact on the Company. Mr. Grant shows that there will be an annual revenue deficiency of $1.2 million attributable to customer growth and plant investment during 2006. Mr. Grant also explains that, because the CWIP balance is composed of many short-lived construction projects, not including CWIP in rate base will hurt UNS Gas' earnings. Including CWIP will help UNS Gas' cash flow *and* its level of earnings. And requesting CWIP in rate base does not dampen the positive effects of the negative acquisition adjustment to ratepayers established in Decision No. 66028 (July 3, 2003) approving the UniSource Energy Corporation ("UniSource") acquisition of the electric and gas assets formerly owned by Citizens Communications Company ("Citizens"). Customers are receiving the full benefit of the negative acquisition adjustment. UNS Gas provides more than substantial evidence as to why the Commission should approve including CWIP in rate base.

2. Geographic Information System ("GIS") Expenditures.

Both Staff and RUCO oppose the Company's proposed treatment of these expenditures. Based upon a directive from the Commission's Pipeline Safety Section to Citizens in 2002, the Company initiated locating and mapping into GPS all existing service lines. Mr. Dallas J. Dukes for UNS Gas explains that the Company had believed that this was a capital project, until the misclassification was corrected in the final quarter of the test year. But the fact remains that these costs are to ensure safe and reliable service to customers, and will benefit present and future customers. Neither Staff nor RUCO state that the expenditures are imprudent. The Company does not need an accounting order for the Commission to determine and grant rate base treatment and recovery as requested in this case. The Company believes it has provided substantial evidence warranting its requested rate base treatment and Mr. Dukes details that evidence in his Rebuttal Testimony.

3. Pre-acquisition gross plant and reducing Test-Year Accumulated Depreciation.

Ms. Karen G. Kissinger discusses these adjustments in detail in her Rebuttal Testimony. RUCO contends that UNS Gas did not substantiate plant additions made from October 29, 2002, through August 11, 2003 (*i.e.* from the date of the Acquisition Agreement to the date when the acquisition was completed.) Ms. Kissinger provides several exhibits in her Rebuttal Testimony showing how UNS Gas maintained its records in accordance with the FERC Uniform System of Accounts ("USOA") or received approval for the final accounting for the acquisition of the former Citizens' electric and gas assets. Also, Ms. Kissinger notes that the Company provided in data responses the analyses and reconciliation for Plant in Service and CWIP from December 2001 through August 2003 received from Citizens, as well as monthly reports, fixed asset and depreciation files for UNS Gas. Combined audited financial statements for 2002 were provided in data responses substantiating the amounts RUCO questions.

Ms. Kissinger also provides a detailed analysis showing how the Commission implicitly accepted the depreciation rates the Company uses in this case. RUCO advocates using depreciation rates from Decision No. 58664 (June 16, 1994), which was a rate case for the gas assets then owned by Citizens. But while Decision No. 66028 -- and the Settlement Agreement approved by that decision -- do not specifically mention new depreciation rates, Ms. Kissinger shows that Exhibit B to that Agreement includes the new depreciation rates proposed originally in Citizen's request in its rate case filed in 2002. Based on that evidence, it is clear the depreciation rates UNS Gas uses here are the same rates used to calculate the revenue requirements that were approved in Decision No. 66028.

4. Compensation Adjustments.

Instead of looking at these programs as a net savings to customers, Staff and RUCO merely look at these programs as additional costs. That is inappropriate. Programs like UNS Gas' Performance Enhancement Plan ("PEP") are geared heavily toward providing benefits to customers and reducing costs to customers, while also promoting increased safety and customer service. Programs like the PEP motivate and encourage employees to be more efficient and improve performance. As Mr. Dallas J. Dukes explains in his

Rebuttal Testimony, the PEP is really "at risk compensation" and average PEP payouts are necessary to attract and retain employees. The term "Incentive Compensation" that Staff and RUCO use to describe these plans and programs is inaccurate. Similarly, UNS Gas also opposes disallowances to Officer's Long Term Incentive Program because those costs are a vital component to a competitive compensation program for Officers' total compensation. Mr. Dukes describes how the Company has a reasonable compensation program in order to keep valued executives to the benefit of customers. For the same reasons, the Company opposes Staff's treatment of its Deferred Compensation Plan. Finally, Mr. Dukes explains how Staff's and RUCO's adjustments to the Company's proposed Supplemental Executive Retirement Plan ("SERP") expenses are inappropriate.

5. Other Rate Base and Operating Income Adjustments.

Mr. Dukes discusses many other Staff and RUCO adjustments in his testimony and shows why the Company believes its requests are appropriate, or offers a modification to the Company's original position. Those areas include the following:

- Nonrecurring Severance Payment Expense.
- Legal Expense.
- Workers Compensation Expense.
- Membership and Industry Association Dues.
- Fleet Fuel Expense.
- Postage Expense.
- Corporate Cost Allocations.
- Bad Debts and Uncollectible Expense.
- Out-of-Period Expenses.
- Customer Service Costs.
- Rate Case Expense.

- So-called "Unnecessary" Expenses. I note that Gary A. Smith also provides Rebuttal Testimony on this subject. In short, the Company should not be required to provide specific documentation for every single item out of the hundreds of items under $50. Such a standard would be absurd and would require the Company to undergo a costly and burdensome process that would benefit no one. Even so, Mr. Smith provides ample description of how these expenses relate to performing leak surveys, safety audits, and training in operations, welding and emergency response – where personnel are on the road for significant periods of time. Further, RUCO also disallowed amounts directly related to preserving the safety of pipelines. To disallow these amounts would be unfair.

III. COST OF CAPITAL.

Q. What are the cost of capital recommendations from Staff and RUCO?

A. Staff recommends an overall cost of capital of 8.12%, based on a cost of equity of 10.0%, a cost of debt of 6.60% and the capital structure of 44.67% equity and 55.33% debt. RUCO recommends an overall cost of capital of 7.93%, based on a cost of equity of 9.64%, cost of debt of 6.23% and a hypothetical capital structure of 50% debt and 50% equity. Neither Staff's nor RUCO's recommendations are sufficient or reasonable.

Q. What was the Company's cost of capital recommendations in its Direct Testimony?

A. Mr. Kentton C. Grant for UNS Gas explained in his Direct Testimony the reasons that the Company's 8.80% cost of capital recommendation was just and reasonable. His conclusion was based on a cost of equity of 11.0%, a cost of debt of 6.60% and a hypothetical capital structure of 50% equity and 50% debt. The Company stands by its recommendations here. In his Rebuttal Testimony, Mr. Grant details the problems with both Staff's and RUCO's recommendations.

Q. Would you highlight some of those problems?

A. Certainly. Neither Staff nor RUCO account for the increased business risks faced by UNS Gas, nor do they account for the Company's need to raise substantial additional capital to fund the significant amount of growth occurring within UNS Gas' service territory. Also, neither Staff nor RUCO did any analysis on how their recommendations affect the Company's cash flow or earnings. While Arizona may be a fair value state, this does not mean factors like the Company's ability to attract capital or its financial integrity should be ignored. The Company is not proposing a new ratemaking methodology; rather, UNS Gas is requesting the Commission to look at these important factors within the regulatory framework established. The bottom line is that the Company will be at a competitive disadvantage when it comes to attracting capital compared to other gas distribution companies if either Staff's or RUCO recommendations are adopted.

Q. In light of the recent decision involving *Chaparral City Water Company*, is UNS Gas modifying its overall rate of return recommendation?

A. Yes. UNS Gas believes its cost of capital recommendation of 8.80% should be applied to fair value rate base. That is, UNS Gas' 8.80% cost of capital should also be its rate of return on its fair value rate base. But to the extent this calculation would result in a higher rate increase than originally proposed by the Company, UNS Gas would still propose to be limited to the original rate relief sought in the Company's rate application.

IV. DEMAND-SIDE MANAGEMENT ("DSM").

Q. Will an additional witness testify in response to Staff's Direct Testimony about DSM?

A. Yes. Ms. Denise A. Smith – who is the Director of Conservation and Renewable Programs at Tucson Electric Power Company ("TEP") – is providing Rebuttal Testimony on DSM issues. I will provide some general comments here.

Q. What are your general comments regarding Staff's Direct Testimony regarding DSM?

A. The Company is not opposed to many of Staff's recommendations on DSM. We are willing to abide by the following Staff recommendations:

- That UNS Gas will file detailed program proposals as soon as possible, even though the Company still plans joint implementation of some measures with UNS Electric, in order to achieve economies of scope and scale.
- That UNS Gas will file a portfolio plan and individual DSM program proposals for the programs the Company is recommending be implemented for UNS Gas customers.
- That UNS Gas continues to monitor and evaluate its DSM programs to make sure those programs are operating effectively. To do so, the Company is proposing a baseline study as a necessary component to assess the success level for each program.
- That UNS Gas provides more detailed information about how UNS Gas markets the Low-Income Weatherization ("LIW") program.

Having said that, the Company does have some concerns with, and recommends some modifications to, Staff's position.

Q. What changes is UNS Gas proposing?

A. First, the Company is concerned about Staff's emphasis on the Societal Cost Test to determine the cost-effectiveness of particular DSM programs. We do not believe that should be the only test used to evaluate programs. The Company has an obligation to balance costs to ratepayers and other economic concerns with environmental concerns. To do that, the Company believes several tests should be employed to evaluate DSM programs – including the Total Resource Cost Test and the Ratepayer Impact Measure. Ms. Smith will discuss these in more detail. Also, UNS Gas believes it can provide a more comprehensive report annually within 90 days after the end of each year. Staff is recommending reports be filed twice a year.

Q. What about Staff's proposed DSM Adjustor Mechanism?

A. While the Company agrees with the Staff's recommendation to utilize a DSM Adjustor Mechanism, we propose to include 50 percent of the funds estimated for new DSM programs and the cost of the LIW program in the DSM Adjustor Mechanism immediately upon the Commission rendering a decision in this case. UNS Gas is very close to implementing several programs and to not allow some recovery of these start-up costs precludes the Company from recovery for several months. So, instead of $0.00082 per therm, the Company proposes to recover $0.004148 per therm through the DSM Adjustor Mechanism when the Commission issues an order in this case.

V. <u>UNS GAS' PGA AND GAS PROCUREMENT ISSUES</u>.

Q. What is UNS Gas' response to Staff and RUCO's recommendations about the PGA?

A. Both Staff and RUCO disagreed that the bandwidth should be removed. We still believe that the bandwidth both prevents customers from receiving accurate price signals and increases the chances that large deferrals will occur in the PGA bank balance. Mr. David

Hutchens will detail this problem in his Rebuttal Testimony. But the Company can accept RUCO's recommendation to increase the bandwidth from \$0.10 per therm to \$0.20 per therm. Staff recommends only increasing the bandwidth to \$0.15 per therm

Further, we understand and support Staff's rationale that no threshold for under-collected balances should trigger an application for a PGA surcharge. This will allow us the flexibility to seek more modest surcharges when needed. We can also abide by \$10 million threshold for over-collections. With regards to the PGA bank interest rates, the volatility and one-directional nature of bank balances (*i.e.* those balances being constantly under-collected) has been different than what was originally envisioned. UNS Gas is merely asking to recover the actual borrowing rate for the PGA bank balance, and propose that this interest rate apply to both over- and under-collected balances.

Q. What is your reaction to Staff's recommendations about UNS Gas' Procurement Practices?

A. I am disappointed that Staff is recommending that UNS Gas' Price Stabilization Policy not be approved. As I emphasize in my Direct Testimony, we are trying to encourage active Staff participation before the fact, so that we can avoid trying to recreate circumstances that existed at the time of purchase which is very difficult to do with volatile and quickly-changing prices. In order to alleviate Staff's concerns, we are proposing to remove options with substantial cost for premiums. The Company also commits to continuing its detailed review of its Procurement Practices and providing this policy for the Commission's review and approval. We would re-urge our original request that the Commission approve its Price Stabilization Policy, for the reasons Mr. Hutchens further explains in his Rebuttal Testimony.

I am encouraged, however, that Staff found the Company's practices reasonable and prudent. But Staff was mistaken about some aspects of UNS Gas' procurement practices. For instance, UNS Gas' practices are significantly different from those of Citizens, because we acquire a portion of gas supplies 36 months in advance of actual deliveries. In addition, Mr. Hutchens also addresses portions of Staff witness George E. Wennerlyn's analysis, looking at prices UNS Gas paid versus the spot market prices. Mr. Hutchens shows that UNS Gas saved its customers $6.5 to $9 million through hedging in advance in accordance with UNS Gas' Price Stabilization Policy during the audited period (September 2003 through December 2005). Mr. Hutchens also provides testimony showing that using the 36-month purchasing strategy did not result in additional cost to the Company.

VI. RATE DESIGN AND LOW INCOME PROGRAMS.

Q. What is your response to the alternative rate design proposals?

A. I am not surprised that neither Staff nor RUCO fully endorse our proposed rate design. But I am surprised Staff and RUCO basically ignore the fact that under UNS Gas' current rate design, cold-weather customers – particularly high-use customers – subsidize warm-weather customers. There is no doubt that distribution costs are largely fixed costs, yet the bulk of these costs are recovered through volumetric rates. UNS Gas' proposed rate design sought to provide more rate stability to the Company. At the same time, the Company proposed seasonal rates so that cold-weather customers would not subsidize warm-weather customers to the degree that subsidization is occurring now. We also want to send significantly more accurate price signals through rates. Unfortunately, neither Staff's nor RUCO's proposals really get us significantly closer to sending accurate price signals. To these points, Mr. D. Bentley Erdwurm provides significant detail justifying the Company's proposed rate design in his Rebuttal Testimony.

Q. Why do you believe the Company's rate design proposal will not stifle conservation?

A. Because the cost of gas will still provide a strong incentive for customers to conserve. The current and projected price of natural gas ranges from 60 to 70 cents per therm. That price is reason enough to provide incentive to customers to conserve using natural gas whenever they can. And because the base cost of gas will be zero and because the entire cost of gas will be part of the Company's PGA, customers will realize what the true cost of natural gas is, and therefore better understand how their natural gas use directly affects their bills. In short, customers will very likely conserve due to the price and volatility of natural gas prices; the Company's rate design will not dampen this incentive. Neither Staff nor RUCO can show that a decrease of 12 cents per therm in the volumetric rate will halt or even slow down customers' incentive to conserve, when natural gas prices are between 60 to 70 cents per therm.

Q. Do you have any comments about Staff's testimony regarding the Customer Assistance Residential Energy Support ("CARES") program?

A. Yes. UNS Gas continues to believe that a flat monthly discount of $6.50 per month is preferable to maintaining the current discount of $0.15 per therm for the first 100 therms during the winter months. We further disagree with Staff's position that the incentive to conserve is removed by changing the discount, for reasons explained in Mr. Erdwurm's Rebuttal Testimony.

Q. Will the Company work towards expanding participation in the CARES programs to eligible customers?

A. Yes. Gary A. Smith discusses this in his Rebuttal Testimony.

Q. Miquelle Scheier, the witness for the Arizona Community Action Association ("ACAA"), describes ACAA's concerns about UNS Gas' proposals with regards to rate design and low income programs. Do you have a general response to her Direct Testimony?

A. Yes. Mr. Smith will discuss and respond to all of ACAA's concerns in his Rebuttal Testimony, but let me start out by saying that the Company is always willing to sit down with ACAA and try its best to address ACAA's concerns. That being said, the Company has proposed rates to best shield low-income customers while also designing rates to best give it the opportunity to recover its revenue requirement. The Company believes it struck that balance with its rate design. For many of ACAA's other concerns, the Company is not quite sure what ACAA is requesting and needs further clarification.

I was disturbed to learn of ACAA's accusations that UNS Gas is somehow referring customers to "predatory lenders" who charge additional fees. I believe Ms. Scheier to be mistaken. My understanding is that the Company has not encouraged customers to use pay day loan businesses to pay their bills. But the fact remains that some customers choose to do so nonetheless. The Company, however, covers bill payment fees for customers who pay in cash at payment locations so long as they are not near a UNS Gas facility. Mr. Gary Smith responds to this allegation in his Rebuttal Testimony.

VII. THROUGHPUT ADJUSTMENT MECHANISM ("TAM").

Q. Do you still believe that the Commission should approve the TAM?

A. Yes. If the Commission truly wants to encourage and support conservation of natural gas, then it must look at non-traditional means to break the link between customer's use of natural gas and the Company's ability to earn its rate of return being tied to the consumption of natural gas. Adopting a decoupling mechanism will promote energy efficiency because the Company does not have to rely on customers using natural gas in order to have that opportunity to earn its return. Mr. Erdwurm provides further testimony on the TAM and why it should be approved.

Q. Are you personally aware of support for similar types of decoupling mechanisms from other organizations?

A. Yes. I know that the American Gas Association ("AGA"), the American Counsel for an Energy-Efficient Economy ("ACE[3]") and the Natural Resources Defense Council ("NRDC") issued a joint statement to the National Association of Regulatory Utility Commissioners ("NARUC") in 2004 supporting decoupling mechanisms like what UNS Gas proposes here. Further, NARUC issued a resolution on November 16, 2005, emboldening state commissions to consider decoupling mechanisms. I know decoupling mechanisms have been approved in several states. Mr. Erdwurm will provide more detail on this in his Rebuttal Testimony.

VIII. WITNESSES.

Q. Mr. Pignatelli, who are the witnesses providing Rebuttal Testimony for UNS Gas?

A. The witnesses who provided Direct Testimony who are also providing Rebuttal Testimony are as follows:

- Mr. David G. Hutchens.
- Mr. Kentton C. Grant.
- Mr. Dallas J. Dukes.
- Ms. Karen G. Kissinger.
- Mr. Gary A. Smith.

In addition, Ms. Denise A. Smith will provide Rebuttal Testimony regarding the Company's DSM programs. Finally, Mr. D. Bentley Erdwurm provides Rebuttal Testimony regarding rate design issues, the CARES program and the Company's proposed TAM and will adopt Mr. Tobin L. Voge's Direct Testimony in this case.

Q. Does that conclude your Rebuttal Testimony?

A. Yes it does.

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Rebuttal Testimony of

David G. Hutchens

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same David G. Hutchens that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Which Commission Staff and/or Intervenor Direct Testimony will you be addressing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I will be addressing; 1) portions of Mr. Robert Gray's Direct Testimony for Commission Staff and Ms. Marylee Diaz Cortez's Direct Testimony for Residential Utility Consumer Office ("RUCO") on the Company's proposed changes to its purchased gas adjustor ("PGA") Mechanism; 2) Mr. George E. Wennerlyn's Direct Testimony for Commission Staff on the benefits of UNS Gas' Price Stabilization Policy; and 3) Mr. Jerry E. Mendl's Direct Testimony for Commission Staff on the various comparisons of UNS Gas' Price Stabilization Policy versus other methods and timing, as well as his recommendation that the Commission not formally adopt UNS Gas' Price Stabilization Policy.

II. THE PGA MECHANISM.

Q. Please provide an overview of the Intervenors Direct Testimony on UNS Gas' proposal to set the base cost of natural gas to zero.

A. Mr. Gray and Ms. Diaz Cortez both agree with the Company's recommendation to set the base cost of gas at zero with a few caveats relating to customer education and transition.

Q. Please provide your response to Mr. Gray's and Ms. Diaz Cortez's Testimony.

A. The Company agrees to provide customer education and transition provisions as Mr. Gray sets forth in his Direct Testimony. I note that these are the same provisions that the Commission approved for Southwest Gas Corporation in its last rate case – Decision No. 68487 (February 23, 2006).

Q. Please provide an overview of the Intervenors' Direct Testimony on UNS Gas' proposed elimination of the PGA Bandwidth?

A. Mr. Gray for Staff states in his Direct Testimony, at page 7, lines 19 through 21, that he "believes that some movement to a wider bandwidth is warranted, but that UNS' proposal to eliminate the bandwidth or expand it to $0.25 per therm is moving too far." Staff recommends that the PGA Bandwidth be expanded from the current $0.10 per therm to $0.15 per therm. Ms. Diaz Cortez for RUCO also does not support elimination of the PGA Bandwidth, but recommends doubling the bandwidth to $0.20 per therm.

Q. What is your response to Staff's and RUCO's Testimony on the PGA Bandwidth?

A. While both provide some relief to the issue presented by the Company, UNS Gas still believes that eliminating the PGA Bandwidth is still the best long-term solution given the current PGA Mechanism structure. The PGA Mechanism already mitigates significant month to month movement in the PGA Rate by using a 12-month rolling average of gas costs to set the rate. This often creates a lag on collecting actual gas costs. Any bandwidth restriction only exacerbates the issue of large deferrals going into a large bank balance. When the bandwidth is met, the PGA Rate is limited from responding to the higher gas costs and these costs are then accumulated in the bank balance for future recovery from customers. At this point, the bandwidth creates a larger disconnect between the gas costs that the Company actually has incurred and/or is incurring, and what customers are paying through their bills. So, customers are *not* receiving accurate price signals needed to modify their gas consumption, and are deferring much of the actual costs that they will eventually have to pay, or future customers will have to pay, through a surcharge.

Q. Have other utilities under this Commission's jurisdiction received significant PGA Bandwidth increases?

A. Yes. In Decision No. 68599 (March 23, 2006) the Commission approved a PGA Bandwidth for Duncan Rural Services Corporation ("Duncan") that can change up to $0.10 per therm *per month*, in essence providing the opportunity for the PGA Rate to change up to *$1.20 per therm per year*.

Q. Does this change the Company's position on eliminating the PGA Bandwidth?

A. No. To the contrary, it supports it. Duncan's band is 12 times the current UNS Gas band and still six times that proposed by RUCO. For all practical purposes, Duncan's wide band is equivalent to removing it altogether.

Q. Given Staff's and RUCO's Testimony on the PGA Bandwidth, can you see any common ground with the Company's proposal?

A. Yes. Given that Mr. Gray stated in his Direct Testimony at page 8, lines 1-2, that "Staff remains open to consideration of further changes to the PGA Mechanism in the future, as may be warranted", the Company believes RUCO's $0.20 per therm PGA bandwidth recommendation represents a reasonable compromise. The Company would also propose that the Commission look at wholesale changes to the PGA Mechanisms to provide more clear and prompt price signals to natural gas consumers.

Q. Please provide an overview of the Intervenors' Direct Testimony on UNS Gas' proposed change to the PGA Bank Balance Threshold?

A. Staff recommends eliminating the under-collected balance threshold and setting the over-collected threshold at $10 million. RUCO agrees with the Company's proposal to make the under-collected and over-collected thresholds symmetric at $6.24 million.

Q. Do you see any issues with eliminating the under-collection threshold as proposed by Staff?

A. No, not when taken in the context of Staff's entire testimony on the matter. Mr. Gray for Staff acknowledges at page 9, lines 8-9, the flexibility currently afforded the Company in the existing mechanism in practice. He states "LDC's have always had the flexibility to file for a PGA Surcharge (or credit) at any time as they see fit." This same flexibility is provided if the under-collection threshold is eliminated. Mr. Gray states – at page 10 at lines 12-16, in his Direct Testimony – that "[elimination] of the threshold on under-collections would, in essence, provide the utility with the discretion to apply for a PGA surcharge when it believes such an action is warranted, while also providing the flexibility for UNS to avoid such an action if the Company believes changing market conditions do not require such a filing." In other words, because the Company already has the discretion to file for a surcharge whenever it sees fit, the Company believes that Mr. Gray is reflecting that fact by simply recommending that the under-collected threshold be eliminated. The Company has no problem with that recommendation.

Q. Does the Company have any concerns with the $10 Million threshold on over-collections?

A. No. While the Company proposed lower, symmetric thresholds for over and under-collections in this case, Staff's explanation of the merits of maintaining some, larger over-collection threshold is well reasoned.

Q. Please provide an overview of the Intervenors' Direct Testimony on UNS Gas' proposed PGA Bank interest rates?

A. RUCO recommends using UNS' proposed interest rate of LIBOR plus 1.5% for the bank balance. Staff recommends retaining the existing interest rate that is applied to UNS' PGA Bank Balance (*i.e.* the monthly three-month commercial financial paper rate), or in the alternative using the one-year nominal Treasury constant maturities rate. Neither party agrees with the Company's proposal of using its weighted average cost of capital ("WACC") when the balance exceeds two times its $6.24 million threshold.

Q. Does the Company propose any change to its filed PGA bank interest rate?

A. Yes. Subsequent to its rate filing, the Company was able to lower the interest rate on its short-term revolving credit facility to LIBOR plus 1%. It is this rate that we would now propose be used for the PGA bank balance.

Q. Did Staff have issue with the LIBOR-based rate?

A. Yes. Staff states that the interest rates applied to PGA bank balances were never meant to reflect the LDC's expected costs of borrowing.

Q. Do you have any comments on this view?

A. Yes. While the interest rates may not have been historically designed to reflect the LDC's expected costs of borrowing, the size, duration, and one-directional nature of bank balances that the LDC's have seen over the last several years were likely not envisioned at the time the PGA mechanism was developed. It was anticipated that the bank balance would fluctuate around zero with no significant mismatch in over- and under-recovery periods. Therefore, any mismatch that did occur would be insignificant. In order to prevent the LDC from incurring costs that it cannot recover, the interest rate on the bank balance should reflect its cost of borrowing.

Q. Would the LIBOR-based apply to both over- and under-collected balances?

A. Yes. The Company would credit the bank balance at this same rate providing this higher benefit to customers for over-recovered balances. This makes it completely fair and balanced and aligns Company and customer interests for a bank balance that oscillates around zero.

III. <u>PROCUREMENT PRACTICES</u>.

Q. Please provide an overview of your rebuttal on the procurement practice submitted by Staff witnesses George E. Wennerlyn and Jerry E. Mendl?

A. While both Mr. Wennerlyn and Mr. Mendl find the Company's procurement practices reasonable and prudent, I would like to make a few clarifications and comments on their analyses and recommendations. I also address Mr. Mendl's recommendation that the Commission not approve UNS Gas' Price Stabilization Policy.

Q. Is Mr. Wennerlyn's correct in his belief that UNS Gas' gas purchasing practices are similar to Citizen Communications Company's ("Citizens") practices?

A. No. Mr. Wennerlyn states in his Direct Testimony at page 7, lines 7 to 9, that "Citizens' gas purchasing practices were similar to those followed by UNS Gas after the acquisition. Both had a plan to begin acquiring a portion of required gas supplies 36 months in advance of actual deliveries." This was not the case. Citizens only started acquiring gas supplies 12 months in advance of actual deliveries. Immediately after the acquisition of Citizens' gas assets, UNS Gas revamped the Citizens Stabilization Policy and incorporated it into the UniSource Energy's Risk Control Policies. This incorporation included adopting UniSource Energy's strict transactional controls and administrative oversight and putting the policy under the purview of its Risk Management Committee. More substantially, the new policy required starting acquiring gas supplies 36 months in advance of actual deliveries.

Q. Do you have any comments about Mr. Wennerlyn's comparison of UNS' Weighted Average Cost of Gas ("WACOG") vs. Market WACOG that he provides on page 9 of his Direct Testimony?

A. Yes. In Exhibit GEW-2 Mr. Wennerlyn's "Retail Purchase Volumes" excludes pipeline fuel and is therefore actually a "city-gate" delivered volumes. This approach overstates the "Retail Commodity Only" price on GEW-2 and thus understates the savings of UNS Gas' procurement practices. The "Retail Purchase Volumes" must be corrected to make its purchase costs and volumes both reflect "point of purchase." This is required in order to make a valid comparison to Mr. Wennerlyn's Market WACOG, which is also based on "point of purchase." When that is done, the savings increase from about $316,000 to over $6 million as I demonstrate in Exhibit DGH-2. In addition, although Mr. Wennerlyn's comparison of UNS Gas' total average WACOG versus a First of the Month ("FOM") index is a good barometer for procurement performance, it does not reflect a truly accurate benchmark. This is because UNS Gas' requirements cannot all be purchased at FOM prices as purchases need to be made in the daily market to account for daily load variation.

Q. How much were UNS Gas' Price Stabilization purchases above or below the spot market prices?

A. When the volume weighted hedge purchases that UNS Gas made under its Price Stabilization Policy are compared to FOM index pricing UNS Gas has saved approximately \$6.5 million during the audited period (September 2003 through December 2005). These same purchases resulted in approximately \$9 million of savings when compared to the spot market Gas Daily Index. These comparisons are shown in Exhibit DGH-3. No matter which index benchmark is used for comparison, it is clear that hedging in advance in accordance with UNS Gas Price Stabilization Policy during the audited period saved UNS Gas customers between \$6.5 and \$9 million.

Q. Would you agree with Mr. Wennerlyn's conclusion that there was a "cost" to the 36-month purchasing strategy?

A. Not in this specific instance. While generally you would expect some cost associated with hedging, UNS Gas' Stabilization Policy purchases resulted in substantial savings compared to the FOM and daily spot indices. Moreover, when you compare UNS Gas' 36-month advance purchase strategy to Citizens' 12-month advance purchase policy, UNS Gas saved a substantial amount because during the September 2003 to December 2005 period markets were trending upward. For example, purchases made in 2004 for delivery in December of 2005 were due to the 36-month methodology. Had a 12-month methodology continued to be employed then the average purchase price of December 2005 hedged volumes would have been closer to the cost of 2005 purchases (\$8.21) than the final average hedged price of \$6.26. The fixed price hedges for December would have then cost UNS Gas approximately $2 million dollars more if Citizens methodology were used.

Q. Please explain your understanding of what the table on page 12 of Mr. Mendl's Direct Testimony?

A. My understanding is that Mr. Mendl's table shows the distribution of gas hedges purchased from September 2003 through December 2005 that were for delivery in that same period. Each column sums to 100% to show how all purchases made during this period compare to the total hedged volume for the period.

On Mr. Mendl's table, all purchases range from 1% to 9% except for three purchases which range from 17% to 24%. These three purchases were executed in 2004 and were larger than normal due to make up purchases required for 2005 to transition from Citizen's 12-month forward purchase schedule to the UNS Gas 36-month forward purchase schedule. The 1% to 9% range was driven by two main factors:

1. Percentages vary due to changes to the annual forecast from one year to the next.
2. Taking discretionary purchases into consideration as mentioned by Mr. Mendl.

Q. Please explain why you disagree with Mr. Mendl's recommendation that the Commission should not approve UNS Gas' Price Stabilization Policy?

A. Mr. Mendl lists several reasons why the Policy should not be adopted by the Commission. I will address these reasons individually.

Q. **Please address Mr. Mendl's concern that the Policy would allow UNS Gas to stabilize prices using options and collars which could add to the cost without commensurate benefit to the ratepayer.**

A. This concern is unfounded. First, UNS Gas has never used these instruments and only has them as secondary hedging mechanisms to maintain the flexibility in its hedging instruments. Second, as Mr. Mendl points out, these options *could* incur substantial costs for premiums but do not necessarily do so. Mr. Mendl seems to portray all options with the same broad brush when some instruments, such as costless collars, do not require any premium payment.

Q. **Is there a solution to eliminate Mr. Mendl's concern that approval of the Policy would give some presumption of prudence for options that could incur these substantial costs/premiums?**

A. Yes. The Company would agree to remove these types of options from its Policy until a time when the use of these instruments has been fully vetted by stakeholders and approved by the Commission.

Q. **Please address Mr. Mendl's concern that approval of the Policy would put the Company on "autopilot" and not continually review its purchasing strategy.**

A. This is both inconsistent with the Company's behavior and the Policy itself. The UniSource Energy Corporation Energy Risk Control Policies Manual requires its Risk Management Committee to review and approve its policies (including UNS Gas Price Stabilization Policy) at least annually and more frequently as changes are required. This requirement is also part of the UniSource Energy Risk Management Committee Charter. Further, on pages 5 to 6 of my Direct Testimony I describe the annual review requirement. In practice, the Company has been very active in changing its Policy to react to changing market conditions – including the complete revamping of the Citizens'

Policy in 2004 and the changes made for 2006 as explained in detail on page 5 of my Direct Testimony. The Company is committed to continuing this level of detailed, active review of its purchasing strategies whether or not the Policy is approved by the Commission.

Q. Do you have any other comments related to approval of the Stabilization Policy?

A. Yes. First, UNS Gas is committed to providing its annual updated Stabilization Policy to the Commission for review and approval. Attached as Exhibit DGH-4 is the reviewed and approved 2007 Policy. The changes from the 2006 Policy are administrative in nature including names and title changes and the correction Mr. Mendl mentioned in his Direct Testimony at page 21 on lines 8 through 17.

Q. Do you have any comments relating to Mr. Mendl's reference to the Sierra Pacific order?

A. Yes. First, as described above, UNS' Policy provides for annual reviews to address evolving market conditions. Second, Mr. Mendl's recommendation on page 24, line 20 of his Direct Testimony that "changes in market conditions would invalidate the approval" is exactly the type of vague hindsight review that the Company is trying to avoid with Commission approval of its Policy. The Company is committing to annual reviews and receiving input from the Commission, its Staff and other stakeholders to ensure the Policy meets the interests of all parties. The Company does not make any profit on the gas it purchases and always has the interests of its customers in mind to secure fairly priced, reliable gas supplies. It would not be acceptable for the Company to implement a procurement policy that could later be second-guessed due to something as vague as "changes in market conditions."

Q. Does this conclude your Rebuttal Testimony?

A. Yes it does.

EXHIBIT

DGH-2

UNS Gas - Monthly WACOG Calculation

Source: from Monthly filed PGA reports and Data Requests BG 3.1 through BG 3.5, and BG 4.1, 4.2, 4.11, and 4.13
Note: "Retail" here means the gas cost for a retail customer, at the point of purchase. It does not signify cost at either the city-gate or the burnertip.

		From PGA monthly reports			From Supply Basin Mix Report:			Basin Market Price (first of the month) Comparisons to UNS Retail Price:						Results:		
Month	Year	Retail Commodity Only Gas Cost	Retail Purchase Volumes Dths @ Purch Pt	Retail Commodity Only $/Dth	FOM SanJuan Volumes	FOM Permian Volumes	FOM Waha Volumes	San Juan FOM Price	Permian FOM Price	Waha FOM Price	Market WACOG FOM Price (Basin weighted)	Variance Retail above Market ($ per dth)	Variance Retail above Market (%)	Monthly Variance Retail Commodity above Market	To-date Retail Commodity above Market Commodity	Annual To-date Retail Commodity above Market Commodity
Sep	2003	$ 1,685,734	350,095	$ 4.82	100.0%	0.0%	0.0%	$ 4.44	$ 4.77	$ -	$ 4.44	$ 0.38	8.4%	$ 131,312	$ 131,312	$ 131,312
Oct	2003	$ 2,383,376	496,283	$ 4.80	100.0%	0.0%	0.0%	$ 3.95	$ 4.14	$ -	$ 3.95	$ 0.85	21.6%	$ 423,058	$ 554,370	$ 554,370
Nov	2003	$ 6,160,289	1,404,094	$ 4.39	100.0%	0.0%	0.0%	$ 3.96	$ 4.07	$ -	$ 3.96	$ 0.43	10.8%	$ 600,077	$ 1,154,447	$ 1,154,447
Dec	2003	$ 8,691,238	1,856,765	$ 4.68	100.0%	0.0%	0.0%	$ 4.23	$ 4.36	$ -	$ 4.23	$ 0.45	10.7%	$ 837,122	$ 1,991,569	$ 1,991,569
Jan	2004	$ 10,304,726	2,006,237	$ 5.14	99.4%	0.6%	0.0%	$ 5.13	$ 5.40	$ -	$ 5.13	$ 0.00	0.1%	$ 9,597	$ 2,001,166	$ 9,597
Feb	2004	$ 9,375,716	1,880,716	$ 4.99	99.6%	0.4%	0.0%	$ 5.01	$ 5.13	$ -	$ 5.01	$ (0.03)	-0.5%	$ (47,635)	$ 1,953,531	$ (38,039)
Mar	2004	$ 4,609,917	949,909	$ 4.85	100.0%	0.0%	0.0%	$ 4.40	$ 4.53	$ -	$ 4.40	$ 0.45	10.3%	$ 430,317	$ 2,383,848	$ 392,279
Apr	2004	$ 3,764,404	830,168	$ 4.53	100.0%	0.0%	0.0%	$ 4.46	$ 4.67	$ -	$ 4.46	$ 0.07	1.7%	$ 61,806	$ 2,445,654	$ 454,084
May	2004	$ 2,275,120	469,400	$ 4.85	100.0%	0.0%	0.0%	$ 5.06	$ 5.32	$ -	$ 5.06	$ (0.21)	-4.2%	$ (100,044)	$ 2,345,610	$ 354,040
Jun	2004	$ 1,972,107	379,569	$ 5.20	100.0%	0.0%	0.0%	$ 5.71	$ 6.19	$ -	$ 5.71	$ (0.51)	-9.0%	$ (195,232)	$ 2,150,378	$ 158,809
Jul	2004	$ 1,884,910	361,647	$ 5.21	100.0%	0.0%	0.0%	$ 5.49	$ 5.94	$ -	$ 5.49	$ (0.28)	-5.1%	$ (100,532)	$ 2,049,846	$ 58,276
Aug	2004	$ 1,920,143	363,920	$ 5.28	100.0%	0.0%	0.0%	$ 5.39	$ 5.68	$ -	$ 5.39	$ (0.11)	-2.1%	$ (41,386)	$ 2,008,460	$ 16,891
Sep	2004	$ 1,986,737	409,148	$ 4.86	100.0%	0.0%	0.0%	$ 4.56	$ 4.72	$ -	$ 4.56	$ 0.30	6.5%	$ 121,022	$ 2,129,482	$ 137,913
Oct	2004	$ 3,811,869	804,002	$ 4.74	92.5%	6.5%	1.0%	$ 4.47	$ 4.59	$ 5.37	$ 4.49	$ 0.25	5.7%	$ 204,469	$ 2,333,951	$ 342,382
Nov	2004	$ 9,760,850	1,559,790	$ 6.26	88.0%	9.0%	3.0%	$ 6.90	$ 6.94	$ 6.94	$ 6.90	$ (0.65)	-9.4%	$ (1,009,019)	$ 1,324,931	$ (666,638)
Dec	2004	$ 11,444,743	2,011,175	$ 5.69	95.5%	4.5%	0.0%	$ 5.95	$ 6.17	$ -	$ 5.96	$ (0.27)	-4.5%	$ (541,824)	$ 783,107	$ (1,208,462)
Jan	2005	$ 10,709,176	1,918,243	$ 5.58	96.7%	3.3%	0.0%	$ 5.67	$ 5.58	$ -	$ 5.67	$ (0.08)	-1.5%	$ (161,611)	$ 621,496	$ (161,611)
Feb	2005	$ 8,756,758	1,591,212	$ 5.50	99.6%	0.4%	0.0%	$ 5.43	$ 5.53	$ -	$ 5.43	$ 0.07	1.3%	$ 115,852	$ 737,348	$ (45,759)
Mar	2005	$ 7,808,477	1,458,244	$ 5.35	99.1%	0.9%	0.0%	$ 5.21	$ 5.54	$ -	$ 5.21	$ 0.14	2.7%	$ 206,709	$ 944,057	$ 160,949
Apr	2005	$ 5,178,267	926,331	$ 5.59	100.0%	0.0%	0.0%	$ 6.21	$ 6.37	$ -	$ 6.21	$ (0.62)	-10.0%	$ (574,249)	$ 369,808	$ (413,299)
May	2005	$ 3,110,406	562,457	$ 5.53	100.0%	0.0%	0.0%	$ 6.30	$ 6.27	$ -	$ 6.30	$ (0.77)	-12.2%	$ (433,073)	$ (63,265)	$ (846,372)
Jun	2005	$ 2,150,224	408,760	$ 5.26	100.0%	0.0%	0.0%	$ 5.38	$ 5.66	$ -	$ 5.38	$ (0.12)	-2.2%	$ (48,905)	$ (112,170)	$ (895,277)
Jul	2005	$ 2,063,377	363,207	$ 5.68	100.0%	0.0%	0.0%	$ 6.05	$ 6.71	$ -	$ 6.05	$ (0.37)	-6.1%	$ (134,025)	$ (246,195)	$ (1,029,302)
Aug	2005	$ 2,376,435	375,350	$ 6.33	100.0%	0.0%	0.0%	$ 5.97	$ 6.76	$ -	$ 5.97	$ 0.36	6.1%	$ 135,596	$ (110,599)	$ (893,707)
Sep	2005	$ 2,820,039	399,389	$ 7.06	100.0%	0.0%	0.0%	$ 8.03	$ 8.61	$ -	$ 8.03	$ (0.97)	-12.1%	$ (387,112)	$ (497,712)	$ (1,280,819)
Oct	2005	$ 5,202,655	656,704	$ 7.92	97.2%	2.7%	0.1%	$ 9.52	$ 9.80	$ 10.11	$ 9.53	$ (1.61)	-16.9%	$ (1,054,439)	$ (1,552,151)	$ (2,335,258)
Nov	2005	$ 8,879,039	1,215,379	$ 7.31	95.5%	2.7%	1.8%	$ 10.82	$ 10.75	$ 11.40	$ 10.83	$ (3.52)	-32.5%	$ (4,281,437)	$ (5,833,587)	$ (6,616,695)
Dec	2005	$ 15,073,197	1,913,067	$ 7.88	97.7%	2.3%	0.0%	$ 8.11	$ 8.45	$ -	$ 8.12	$ (0.24)	-2.9%	$ (457,005)	$ (6,290,592)	$ (7,073,700)

	Commodity cost	% variance	Variance	
Total for entire period	$ 156,159,929	-4.0%	$ (6,290,592)	Total for entire period
Year 2005	$ 74,128,050	-9.5%	$ (7,073,700)	Year 2005
Year 2004	$ 63,111,242	-1.9%	$ (1,208,462)	Year 2004
Balance 2003	$ 18,920,637	10.5%	$ 1,991,569	Balance 2003

Note:
Negative number is below market or less than market pric
Positive number is above market or more than market pri

EXHIBIT

DGH-3

Exhibit DGH-3

	Hedged Volume	Average Purchase Price	San Juan FOM	Hedge Savings vs FOM Index	San Juan Gas Daily Daily Index	Hedge Savings vs Daily Index
Sep-03	243,218	$5.470	$ 4.440	(250,514)	$ 4.200	(309,008)
Oct-03	427,872	$5.457	$ 3.950	(644,929)	$ 4.248	(517,327)
Nov-03	728,265	$4.880	$ 3.960	(669,778)	$ 4.133	(543,667)
Dec-03	1,309,564	$5.015	$ 4.230	(1,027,839)	$ 5.381	479,427
Jan-04	1,329,094	$5.050	$ 5.130	106,207	$ 5.374	430,978
Feb-04	1,129,633	$5.005	$ 4.975	(34,054)	$ 4.848	(177,790)
Mar-04	988,878	$4.730	$ 4.400	(326,002)	$ 4.741	11,014
Apr-04	455,323	$4.612	$ 4.460	(69,367)	$ 5.104	223,785
May-04	293,672	$4.732	$ 5.060	96,389	$ 5.344	179,896
Jun-04	201,512	$4.759	$ 5.710	191,667	$ 5.393	127,787
Jul-04	152,650	$4.859	$ 5.490	96,347	$ 5.275	63,577
Aug-04	184,000	$5.185	$ 5.390	37,783	$ 4.993	(35,283)
Sep-04	197,000	$5.172	$ 4.530	(126,526)	$ 4.370	(157,980)
Oct-04	329,000	$5.157	$ 4.470	(226,094)	$ 5.063	(30,870)
Nov-04	578,000	$5.215	$ 6.900	974,137	$ 5.505	167,731
Dec-04	1,161,000	$5.485	$ 5.950	539,539	$ 6.039	642,531
Jan-05	1,275,000	$5.553	$ 5.670	148,804	$ 5.454	(127,172)
Feb-05	934,000	$5.544	$ 5.430	(106,298)	$ 5.471	(68,104)
Mar-05	805,000	$5.489	$ 5.210	(224,502)	$ 6.164	543,494
Apr-05	519,000	$5.114	$ 6.210	568,931	$ 6.325	628,616
May-05	339,000	$5.097	$ 6.300	407,952	$ 5.511	140,470
Jun-05	227,000	$5.079	$ 5.380	68,311	$ 5.766	156,009
Jul-05	173,000	$5.195	$ 6.710	262,169	$ 6.243	181,417
Aug-05	167,000	$5.475	$ 5.970	82,590	$ 7.584	352,133
Sep-05	188,000	$5.567	$ 8.030	463,092	$ 9.170	677,443
Oct-05	305,000	$5.544	$ 9.520	1,212,790	$ 10.272	1,442,180
Nov-05	539,000	$5.679	$ 10.820	2,770,828	$ 7.277	861,061
Dec-05	1,027,000	$6.263	$ 8.440	2,235,902	$ 10.768	4,626,824
				$ 6,557,534		$ 9,969,172

EXHIBIT

DGH-4

UNS Gas, Inc. Price Stabilization Policy

Effective January 1, 2007

Contents

1 Introduction

1.1 Purpose

The UNS Gas, Inc. Price Stabilization Policy addresses the procurement methodology that is to be employed to stabilize the price of natural gas through forward hedging activities.

1.2 Objectives

- Define hedge policy including purchasing mechanisms that can be used to support price stabilization.
- Define and monitor the line of authority, responsibility and accountability.
- Monitor hedge positions and provide periodic reports to Senior Management that details total hedge position.

2 Hedge Procedure

2.1 Overview

The intent of this hedge policy is to create price stability for UNS Gas ratepayers. Due to the recent high volatility in the natural gas markets, over-reliance on spot market purchasing could expose the ratepayer to extreme price fluctuations of natural gas. This exposure combined with the current PGA mechanism for purchased gas cost recovery can also expose UNS to mismatches in revenues and expenses and require frequent PGA adjustments to rectify. Some spot market purchasing is prudent and a portion of the portfolio will be purchased in that manner. Entering into fixed price forward gas purchases will be the primary strategy used by UNS to stabilize gas prices. To execute this strategy several tools will be employed such as forecasts of both demand and gas prices, price and calendar triggers and various purchasing mechanisms.

2.2 Hedge Strategy

2.2.1 Time Horizon

A mix of physical and physical gas acquisitions and their respective time horizons will be the basis for this hedge strategy. This mix will consist of:

- Monthly Purchases (near-term)
- Purchases Less than one year with Fixed Price Transactions (mid-term)
- Purchases Greater than one year with Fixed Price Transactions (long-term)

UNS Gas will begin purchasing for its gas requirements for any given month approximately three years in advance.

2.2.2 Non-Discretionary & Discretionary Purchases

Non-Discretionary Purchases: A target level of 45% of the Estimated Monthly Gas Load prices will be fixed two months prior to the beginning of each month. Non-discretionary purchases will be made utilizing monthly calendar triggers to insure this 45% minimum is met. Purchases will not be made in the months of August through October due to the historical volatility added by hurricanes. During the week of the 20th of each month (the "trigger date"), purchases will be made to bring the total fixed price monthly volume (including discretionary purchases) up to at least the percentage in Appendix 1. The table represents purchasing 15% of the Estimated Gas Load each year so that at the end of 3 years the 45% minimum purchase goal will be realized if no other purchases were made. Monthly purchases should serve to dollar cost average the gas positions and optimize the purchase schedule.

Discretionary Purchases: Discretionary purchases may be made in excess of the Non-Discretionary purchases. In general, these purchases are made with the intent of taking advantage of favorable purchasing opportunities and/or reducing the amount of exposure to spot market prices during periods of high volatility. Any purchase made beyond 36 months will be considered a discretionary purchase. Discretionary and Non-Discretionary purchases will not exceed 80% of the Estimated Monthly Gas Load (70% in March, April, October and November shoulder months) to allow room for index purchasing and act as a buffer for lower than normal load. All discretionary purchases must be approved by at least three members of the RMC.

The Trader will prepare a documentation packet for each stabilization purchase (whether discretionary or non-discretionary) to memorialize the decision process for future reference.

2.2.3 Physical Supply Location

UNS Gas will hedge the majority of its gas requirements at the San Juan supply basin. All physical amounts hedged at San Juan will be within UNS Gas' pipeline allocation from San Juan. These allocation limits may change from time to time and will be updated in the UNS Gas Book with current volumes allowed to be hedged at San Juan. The remaining physical hedges will be made at the Permian basin utilizing UNS Gas' pipeline receipt points.

2.3 Hedge Tools

2.3.1 Estimated Load for Hedging Purposes

UNS Gas' Estimated Load will be based on the annual budget forecasted load. Changes in year over year forecasts should be integrated into the stabilization plan and adjustments made to stay within the percentages discussed in section 2.2.

Natural gas price forecasts will be based on fundamental indicators such as gas storage (both current and projected), temperature forecasts, gas production (both current and projected) and historic gas trends.

2.3.2 Purchasing Mechanisms

The following types of transactions will be used as the primary methods used to achieve price stabilization:

- Fixed price forward physical purchases at supply basins
- Daily swing purchases based on index prices

The following types of transactions will be used as secondary methods to achieve price stabilization:

- Natural gas call options, collars and swaps
- NYMEX Purchases
- Basis Trades to convert NYMEX to physical supply basin.
- Storage

Financial hedges such as swaps or calls should be considered to hedge any percentages above the 45% target level but may not exceed the maximum allowable hedge levels. This will retain operational flexibility for physical gas flow variations while still providing price stabilization.

3 Authorized Transaction Characteristics

In order to control gas purchasing, the following section outlines the specific physical transactions which may be entered into without prior approval from the Risk Management Committee. Any transaction not specifically authorized in this section must be approved by the RMC and receive any other necessary internal approvals.

3.1 Authorized Transactions

The Fuel and Wholesale Power group is authorized to enter into the following physical transactions without prior authorization from the Risk Management Committee within the confines of all controls, limits, and policies. All other transactions must have the express consent of three or more Risk Management Committee members.

- Forward Physical Fixed Price Purchases: Trader may purchase San Juan or Permian gas blocks for terms and volumes described in Section 2.2. Physical purchases of San Juan gas shall not exceed the allowable basin percentage allotment discussed in section 2.2.3. Trader may also purchase NYMEX gas coupled with a San Juan Basis which sum to be the equivalent of San Juan Physical gas.

- Forward Financial Fixed Price Swap Purchases: Trader may purchase San Juan or Permian fixed for index gas swaps for terms and volumes described in Section 2.2. The index should be matched to the desired portion of index purchases to be hedged (either Daily or First of the Month).
- UNS Gas has a program called the Negotiated Sales Program. NSP customers are T-1 Transportation customers who can purchase gas from either UNS or the competitive market. The program allows UNS to sell these customers gas that is purchased on their behalf through UNS' supplier. The NSP Trader interacts with the NSP customers and UNS' key account managers to make forward purchases as requested by the customers. The customers may purchase NYMEX gas, basis or both for forward month deliveries. The NSP Trader will insure that the purchases made are entered into the customer's accounts for future pricing and will also ensure that the transaction is within the credit limit of the customer if necessary. Both the Risk Manager and NSP Trader will insure that UNS does not take on any risk from these transactions by only purchasing gas per the NSP customer requests and insuring all costs are passed directly on to the NSP customer.

4 Transaction Responsibility Assignments

4.1 Stabilization Purchase Execution

A purchase recommendation will be made to the Risk Manager by the Energy Trader responsible for UNS Gas Hedging for all purchases. Upon approval, the trader will place an order (market or limit) with the purchasing agent and consummate if the trigger is subsequently reached. An electronic confirmation will be generated by the purchasing agent and sent to the Energy Trader for filing. A trade ticket will be filled out by the trader with copies routed to the Risk Manager and Risk Controller.

Abbreviations are as follows:

T	- Trader	RM	- Risk Manager
RC	- Risk Controller	A	- Accounting/Billing
FA	- Fuels Analyst		

1) Transaction Activities

a) Execute trade	T
b) Designate Accounting Treatment	T
c) Complete trade ticket	T
d) Enter transaction information in WebTrader	T
e) Ensure transaction is within limits	T, RM
f) Memorialization/Documentation	T

2) Contract Administration

a) Maintain customer trading and scheduling information	T,FA
b) Maintain customer billing information	A
c) Write and route transaction agreements	T
d) Maintain copies of executed transaction agreements	T

3) Transaction Compliance

a) Ensure proper recording of transactions	RM
b) Reconcile confirmation to trade ticket	RC
c) Reconcile transaction agreement to confirmation	T, RC
d) Reconcile confirmation to system data input and lock trade	RC
e) Deliver executed transaction agreement to counterparty	T
f) Ensure that designated hedge volume is within forecast	RM

5) Transaction Settlement

a) Reconcile gas invoices	A
c) Initiate payment	A
d) Ensure appropriate accounting and tax treatments	A
e) Monitor and report late payment and nonpayment	A

6) Position Control

a) Gather and input forward price curves	RC
b) Validate forward price curves	RC
c) Perform monthly portfolio review	RM
d) Prepare and distribute periodic valuation reports	RM
e) Perform credit risk measurement	RC
f) Prepare and distribute periodic credit risk reports	RC
g) Perform market risk measurement	RM
h) Track GAAP and SEC compliance	RC, A
i) Monitor and report violation of authorities, limits and policies	RM, RC

4.2 NSP Purchase Execution

A purchase order will be requested by a NSP customer to the NSP Trader. The NSP Trader will enter into the transaction on the customer's behalf and notify the customer of the exact price and terms. The Administrator will fill out a trade ticket and route copies to the Key Account Manager for NSP's and Energy Settlements and Billing. A copy of the trade ticket will be maintained for the records.

Abbreviations are as follows:

NT - NSP Trader RM - Risk Manager
A - Accounting/Billing

1) Transaction Activities

a) Execute trade	NT
b) Ensure transaction is within customer credit limit	NT

c)	Enter transaction information into Gas Trader	T
2) Contract Administration		
a)	Maintain customer trading and scheduling information	NT
b)	Maintain customer billing information	A
c)	Write and route transaction agreements	NT
d)	Maintain copies of executed transaction agreements	NT
3) Transaction Compliance		
a)	Ensure proper recording of transactions	RM
b)	Reconcile confirmation to trade ticket	RC
4) Transaction Settlement		
a)	Reconcile gas invoices	A
b)	Initiate payment	A
c)	Ensure appropriate accounting and tax treatments	A
d)	Monitor and report late payment and nonpayment	A
5) Monitoring		
a)	Perform periodic NSP reports	NT
b)	Notify RM of NSP issues	NT

4.3 Signing Authorities

Transaction agreements for authorized transactions may be signed by the Risk Manager or any member of the RMC. Other agreements may be signed by the Risk Manager or any member of the RMC necessary once approvals obtained.

4.4 Risk Policy Acknowledgement

The Risk Manager, Risk Controller and each Authorized Trader listed on Exhibit A will sign a copy of Exhibit B, "UNS Gas Hedge Policy Acknowledgement Form". These forms must be filled out for each new revision of this Policy. The Risk Manager will maintain a record of the signed exhibits.

4.5 Ethics/Principles of Conduct and FERC Standards of Conduct

4.5.1 Ethics/Pricples

UniSource Energy Corporation (UNS) has a UNS Code of Ethics and Principles of

Conduct (Code). The objective is to ensure that non-classified employees of UNS and its subsidiaries and the UNS Board of Directors are complying with the Code such that they:

1. conduct their business activities in a way that complies with the law, and
2. ensure their activities meet the highest ethical standards for business conduct.

Policy

- All unclassified employees and members of the Board of Directors will sign a questionnaire regarding compliance with the Code once a year.
- Internal Audit will summarize the completed questionnaires once a year and report thereon to the Audit Committee.
- The Corporate Compliance Officer has the responsibility to report to the Audit Committee whether any fraud as discussed in the Sarbanes/Oxley Act has been identified during the quarter.
- The Corporate Compliance Officer may request executive sessions with the Audit Committee at any time he/she believes it is appropriate.
- Internal Audit is responsible for monitoring and testing for compliance with the Code.

4.5.2 FERC Standards of Conduct

- Additionally, employees are required to complete training to ensure compliance with the Federal Energy Regulatory Commission (FERC) Standards of Conduct and Anti-Market Manipulation Regulations. The Standards of Conduct provide for the independent functioning of the Wholesale Marketing Department and ensure that no undue preference is given to the Marketing Department by the transmission function.

The Anti-Market Manipulation rules are required by the Energy Policy Act of 2005. TEP's policy requires employees to undergo training regarding both sets of regulations on an annual basis. The training will take place using an online program developed by the Edison Electric Institute.

5 Management Reporting Requirements

5.1 Overview of Management Reporting

Accurate and timely information is crucial to the control and management of risk. All Risk Management Committee members, therefore, will receive a comprehensive set of reports on a monthly basis of the business unit's risk profile and performance and updates of trading positions and limits. For the months when a quarterly Risk Management Committee meeting is scheduled, the reports will be distributed prior to the meeting together with written explanation of the major movements, along with the meeting agenda.

The RMC report should be sufficient to provide adequate information to judge the changing nature of the risk profile and the business unit's performance. All RMC members will be trained on the significance and understanding of all reports.

5.1.1 Key Market and Credit Risk Reports

The following is a listing of selected high level reports appropriate for the Risk Management Committee related to this gas stabilization policy.

Gas Hedging Reports

- Current Hedges—Report of current gas hedges including percent of estimated monthly volume hedged, hedged prices, product types and current mark-to-market of hedges.
- Stress market scenario analysis and effect on the PGA bank if requested by the RMC;
- Policy exceptions--description of exceptions with recommendations as to corrective action required;
- New transactions that required RMC approval.

Exhibit A.

Authorized Stabilization Trader
Michael Bowling
Ramondo Robey

Authorized NSP Traders
Craig Lipke
Michael Bowling
Ramondo Robey

Exhibit B.
UNS Gas Hedging Policy Acknowledgement Form

I acknowledge that I have read UNS Gas, Inc. Price Stabilization Policy dated ____________________ and I agree to comply fully with the parameters outlined. I understand that willful violation of limits set within these Policies may result in disciplinary action.

_________________________ (Signature)   ___________________ (Date)

_________________________ (Print Name)

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-063
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kentton C. Grant that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Please provide your general response to the Commission Staff and Intervenor Direct Testimony.

A. The rate increases recommended by the Commission Staff ("Staff") and by the Residential Utility Consumers Office ("RUCO") are insufficient to support the financial integrity of UNS Gas, Inc. ("UNS Gas"). Neither party presented an analysis of how their recommendations would impact the Company's cash flow and earnings, two critical elements to consider when evaluating the ability of UNS Gas to attract capital on reasonable terms. The allowed return on equity ("ROE") and the overall rate of return ("ROR") on invested capital recommended by each of these parties are also unreasonably low in light of the business risks faced by UNS Gas, the impact of growth and regulatory lag on the Company's financial performance, and the need to raise additional capital for plant investment. Finally, Staff and RUCO's rejection of the Company's request to include construction work-in-progress ("CWIP") in rate base appears to be based largely on philosophical grounds and does not take into account the financial realities facing

UNS Gas. Since neither party adjusted the test-ear balance of customer advances that are tied to this CWIP balance, the positions taken by Staff and RUCO actually serve to penalize UNS Gas for having an ongoing construction program. At a minimum, the balance of customer advances related to the test-ear CWIP balance should have been removed by the Commission Staff and RUCO as rate base adjustments. The Company's alternative request for a post test-year adjustment to rate base, which would include that portion of the test-year CWIP balance that has already been placed into service, was not even addressed by RUCO and was summarily dismissed by Staff. I am hopeful that once Staff and RUCO have had an opportunity to evaluate the financial impact of their rate recommendations on UNS Gas, that these parties will at least consider the Company's alternative request for a post-test-year adjustment to rate base.

Q. Which Commission Staff and/or Intervenor testimony will you be addressing in your Rebuttal Testimony?

A. I will be addressing the Direct Testimony of the following witnesses:

- William A. Rigsby on behalf of RUCO (Cost of capital)
- Marylee Diaz Cortez on behalf of RUCO (CWIP in rate base)
- David C. Parcell on behalf of Staff (Cost of capital & CWIP in rate base)
- Ralph C. Smith on behalf of Staff (CWIP and ROR on fair value rate base)

II. <u>REBUTTAL TO RUCO WITNESS WILLIAM A. RIGSBY</u>.

Q. Mr. Grant, could you please summarize your view of the Direct Testimony filed by Mr. William Rigsby on behalf of RUCO?

A. Yes. The allowed ROE of 9.64% recommended by Mr. Rigsby is unreasonably low. The results of his single-stage DCF analysis, which produces cost of equity estimates as low as 7.6% for the companies in his proxy group, should be given little to no weight in this proceeding. The results obtained from his CAPM analysis are more realistic, falling within a range of 9.7% to 11.36%. However, because Mr. Rigsby chooses to base his recommendation on an average of his DCF estimate (8.74%) and the midpoint of the CAPM range (10.53%), the end result of 9.64% is unreasonably low and is not supported by the range established in his own CAPM analysis.

I concur with Mr. Rigsby regarding the appropriate capital structure for UNS Gas. As he points out, the requested capital structure consisting of 50% equity and 50% debt is in line with industry averages. However, regarding the Company's cost of debt, I strongly disagree with Mr. Rigsby's disallowance of debt issuance costs and annual revolving credit fees. It is standard practice for both regulated and unregulated companies to amortize the costs of debt issuance over the respective lives of the debt obligations issued. It is also necessary, especially for a growing company like UNS Gas, to maintain lines of credit to meet short-term liquidity needs and to fund capital expenditures prior to the arrangement of long-term financing. For these reasons, Mr. Rigsby's cost of debt recommendation should be rejected.

Q. Please expand on your critique of Mr. Rigsby's DCF analysis.

A. Certainly. As can be seen on Schedule WAR-2 attached to his Direct Testimony, Mr. Rigsby uses dividend growth rates for his proxy group ranging from a low of 4.14% for WGL Holdings, Inc. to a high of 8.17% for Southwest Gas Corporation. Since these growth rates are used by Mr. Rigsby in a single-stage constant growth DCF model, he implicitly assumes that these growth rates will remain in effect in perpetuity. From the standpoint of market expectations, there are two serious problems with this assumption.

First, compared to most industries, the natural gas distribution industry remains highly regulated and is fairly homogeneous with respect to service offerings and type of capital investment. Although near-term expectations for dividend and earnings growth can vary widely between individual companies, over the long-run it is unrealistic to assume such a wide divergence in growth rates and shareholder returns. Over the long-run, investors are much more likely to expect a convergence of individual company growth rates toward the industry average growth rate. This approach to forecasting long-term growth rates, which assumes that growth rates for individual companies will revert to the industry average over time, is widely practiced by securities analysts and investors. Since Mr. Rigsby did not adjust his perpetual growth rates to account for this factor, the cost of equity estimates he obtained were unrealistically low for companies having the lowest near-term growth rates. Indeed, half of the companies in his proxy group have cost of equity estimates ranging from 7.63% to 8.29%, values that are just barely above comparable utility bond yields.

Second, when adjusted for inflation, the perpetual growth rates used by Mr. Rigsby assume a real rate of growth that is unrealistically low for most of the companies in his proxy group. Based on the difference between the yield on 20-year inflation indexed U.S. Treasury securities (2.45%) and the yield-to-maturity on 20-year fixed-rate U.S. Treasury bonds (4.96%), the expected long-term inflation rate for the U.S. economy was approximately 2.5% as of January 19, 2007, the terminal date used by Mr. Rigsby in his calculation of average stock prices in his DCF analysis. Subtracting this expected inflation rate from the dividend growth rates appearing in his Schedule WAR-2 results in a range of expected *real* dividend growth rates of 1.64% to 5.67%. It is hard to fathom that investors would expect any company, even a highly regulated distribution company, to grow its earnings and dividends at a perpetual growth rate of only 1.64% over the expected rate of inflation. When adjusted for inflation, five of the companies in his proxy group have a perpetual *real* growth rate of 1.81% or less. By contrast, expectations for long-term growth in the overall U.S. economy are likely closer to 3.5% in real terms. It is simply unrealistic to assume that dividends and earnings would grow at such a wide discount to overall economic growth for an industry providing basic utility infrastructure to an expanding U.S. economy.

Q. Do you have any other comments regarding Mr. Rigsby's cost of equity analysis?

A. Yes, I do. At page 52 of his Direct Testimony, Mr. Rigsby dismisses the company-specific risks faced by UNS Gas that were described on page 21 of my Direct Testimony. Despite the fact that UNS Gas is much smaller than any of the companies used in Mr. Rigsby's proxy group, and the fact that UNS Gas is growing at a much faster pace with a detrimental impact on the Company's earned ROR, no upward adjustment was made to his proxy group results to account for this incremental risk. Additionally, even though many of the companies in his proxy group have a rate de-coupling mechanism or weather normalization adjustor that limits financial exposure to mild winter weather and customer conservation, Mr. Rigsby made no upward adjustment to the proxy group results to reflect the increased risk UNS Gas would bear under RUCO's proposed rate design. So, even if the problems with Mr. Rigsby's proxy group analysis were to be remedied, an additional upward adjustment to the proxy group cost of equity would have to be made in order to arrive at a reasonable allowed ROE for UNS Gas.

Q. Do you think Mr. Rigsby has a good grasp of the additional risk faced by UNS Gas resulting from high customer growth and regulatory lag?

A. No, I do not. As stated at page 40 of his Direct Testimony, Mr. Rigsby cites the potential acceleration of growth in new construction projects and home developments in the Company's service territories as a positive factor for UNS Gas. However, as described at page 22 of my Direct Testimony, and in greater detail below in my Rebuttal Testimony to Ms. Diaz Cortez, the Company is negatively impacted over the short-run by high customer growth and related capital spending. Additionally, contrary to the suggestion by Mr. Rigsby at page 40, lines 9-14 of his Direct Testimony, the Company does not foresee – and Mr. Rigsby fails to cite any evidence of – any near-term decline in the cost of goods and services it purchases that could offset this negative impact from growth.

Q. Regarding his recommended cost of debt, does Mr. Rigsby offer any reason for disallowing the Company's debt issuance costs and revolving credit fees?

A. No. He simply states that these costs should have been written off by UNS Gas in prior periods.

Q. Is it customary for utilities to recover their debt issuance costs and revolving credit fees through an adjustment to the cost of debt capital?

A. Yes. Debt issuance costs are typically included in the cost of debt by amortizing these costs over the life of the respective debt obligations, and including this amortization expense as a component of interest expense in the cost of debt calculation. Likewise, since revolving credit fees are recorded as interest expense on a utility's financial statements, and are necessary for purposes of maintaining financial liquidity, it is also customary to include this expense when calculating the cost of debt. UNS Gas has proposed treating these costs in this manner, resulting in a cost of debt of 6.60%.

Q. Is UNS Gas obligated to amortize debt issuance costs over the life of the respective debt obligations?

A. Yes. The accounting guidelines issued by the Federal Energy Regulatory Commission ("FERC") require this method of accounting for natural gas companies. Specifically, these instructions state that "The premium, discount and expense shall be amortized over the life of the respective issues under a plan which will distribute the amounts equitably over the life of the securities." Clearly, UNS Gas is following standard industry practice with respect to its accounting and rate treatment of debt issuance costs.

Q. Does that conclude your rebuttal to the Direct Testimony of Mr. Rigsby?

A. Yes, it does.

III. REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

Q. Mr. Grant, could you please summarize your view of the Direct Testimony filed by Ms. Diaz Cortez on behalf of RUCO?

A. Yes. Ms. Diaz Cortez rejects the Company's request to include CWIP in rate base on several grounds. After describing at length how the rate base treatment of CWIP is not an "accepted" ratemaking treatment, and why the Company must demonstrate that it meets an "extraordinary circumstance" standard, she goes on to state that this ratemaking treatment is not necessary to maintain the Company's financial integrity. Ms. Diaz Cortez also questions the negative effects of regulatory lag and growth on UNS Gas' financial results, and refers to one of the Company's arguments on CWIP in rate base as being "disingenuous at best."

Q. Do you agree with Ms. Diaz Cortez' characterization of CWIP in rate base as not being an "accepted" ratemaking treatment?

A. No, I do not. The inclusion of CWIP in rate base as a means of supporting the financial integrity of public utilities has been an accepted form of ratemaking treatment for many years in many states. Although the standard for granting this ratemaking treatment varies by jurisdiction, I am not aware of any bright-line "extraordinary circumstance" standard that must be met in the State of Arizona to include CWIP in rate base. While I recognize that rate base treatment of CWIP is unusual in the sense that it has not been used for many years in this jurisdiction, it is certainly a tool that is available to the Commission for purposes of setting fair and reasonable rates.

Q. Are you aware of cases where CWIP was included in rate base in Arizona?

A. Certainly. Although I am not an attorney, I am aware of at least two Arizona Supreme Court cases decided in the 1970s that have discussed the issue of CWIP in rate base. For instance, it is my understanding that the Arizona Supreme Court did make the statement – in a rate case involving Arizona Public Service Company ("APS") – that the Commission could adopt any of a variety of approaches and consider plant under construction so long as the approach is not arbitrary.[1] In a subsequent Arizona Supreme Court decision involving an APS rate case, my understanding is that the Court specifically stated that CWIP may be included in fair value rate base and that it was reasonable for the Commission to allow inclusion of CWIP in determining rates.[2] I do not recall there being any language about how "extraordinary circumstances" were needed to put CWIP in rate base.

Q. Even if the Commission were to require a finding of "extraordinary circumstance" in order to allow CWIP in rate base, would UNS Gas meet such a standard?

A. Yes, I believe it would. As discussed at page 22 of my Direct Testimony, it will be difficult, if not impossible, for the Company to earn its authorized rate of return over the next several years. This is due primarily to the high rate of customer growth in UNS Gas' service territory and the wide gap between the Company's embedded cost of plant and incremental cost of plant on a per-customer basis. Additionally, this growth is causing UNS Gas to raise large sums of additional capital to fund necessary plant investments. At this same time, natural gas prices have become much more volatile than in the past, thereby exposing the Company to the risk of large purchased gas deferral balances and declining customer usage. The combination of these factors, in my opinion, constitutes extraordinary circumstances that justify CWIP in rate base.

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[1] Arizona Corp. Comm'n v. Arizona Public Service Co., 113 Ariz. 368, 555 P.2d 326 (1976).
[2] Arizona Community Action Assoc. v. Ariz. Corp. Comm'n, 123 Ariz. 228, 599 P.2d 184 (1979).

Q. At page 9 of her Direct Testimony, Ms. Diaz Cortez characterizes the Company's financial integrity argument as being "without merit." Did Ms. Diaz Cortez offer any financial analysis to support this conclusion?

A. No, she did not. Although she makes reference to the financial integrity of "Arizona utilities" in general, and cites the positive effects of growth and regulatory lag on UNS Gas, she provides no analysis of the Company's financial performance on either an actual or forecasted basis, and provides no quantitative support for her statements regarding regulatory lag and growth.

Q. Do you believe it is necessary to include CWIP in rate base in order to preserve the financial integrity of UNS Gas?

A. Yes, I do. As discussed on pages 27 through 28 of my Direct Testimony, the ability of UNS Gas to earn a reasonable rate of return on its invested capital and to generate a healthy level of internal cash flow is essential if the Company is to maintain continued access to capital on reasonable terms.

Q. Also at page 9 of her Direct Testimony, Ms. Diaz Cortez states that "...the Company's growth argument is without merit as growth has a positive effect on the Company, generating more revenue and cash flow." Do you agree with this statement?

A. No, I do not. While it is true that growth does generate additional revenue, and that over the long-run this growth will generate additional cash flow, Ms. Diaz Cortez ignores the fact that over the short-run the Company's earnings and cash flow are adversely affected by high customer growth. Meeting this growth requires substantial capital investment, currently at a level far exceeding the Company's internal cash flow. This additional investment creates additional fixed costs that UNS Gas must bear, including interest expense, depreciation expense and property taxes. Because of these additional costs, and the regulatory lag resulting from the use of an historical test year and a year-long rate review process, the Company's near-term earnings and cash flow are adversely affected by high customer growth.

Q. Can you provide an example showing the financial impact of customer growth and regulatory lag on UNS Gas?

A. Yes. In order to evaluate the financial impact of growth, we examined the actual growth in customers and net plant investment during calendar year 2006, the 12 month period immediately following the test year ending December 31, 2005.

Page 1 of Exhibit KCG-10 shows the increase in annual fixed costs associated with the $17 million increase in net plant investment that occurred in 2006. Applying the Company's requested pre-tax ROR, the composite depreciation rate and the average property tax rate to this increased plant investment, the Company's annual fixed costs increased by approximately $3.0 million in 2006. As shown on page 2 of Exhibit KCG-10, during this same period the Company added 6,255 customers. Using the normalized use per customer and average revenues per therm from the test year, an increase in annual delivery revenues of $1.8 million was estimated for these new customers. As summarized at the bottom of this same page, the difference between the $3.0 million of increased fixed costs and $1.8 million of increased delivery revenues represents an annual revenue *deficiency* of $1.2 million attributable to customer growth and plant investment. Stated another way, this $1.2 million deficiency represents the gap between the Company's required return on new plant investment and the Company's actual return on new plant investment. As a consequence, arguments to exclude CWIP from rate base on the basis of assumed growth-related benefits to UNS Gas simply do not hold water.

Q. Do you have any other comments regarding the example provided on Exhibit KCG-10?

A. Yes. Since additional operation and maintenance costs were not included in this example, and since the average use per new customer is probably lower than the embedded use per customer due to improved energy efficiencies, this example likely understates the true impact on UNS Gas. Additionally, since the plant investment balances used in the example already take into account the effects of depreciation and plant retirements, the "benefits" of regulatory lag cited by Ms. Diaz Cortez in her Direct Testimony page 9, lines 15-16, have been fully reflected in the analysis. Finally, it should be noted that this quantification of financial impact relates to only a single year. UNS Gas has not had a rate increase since August 2003, and will not be able to implement new rates from this proceeding until August 2007. Due to the passage of time, high customer growth and increasing plant investment on a per-customer basis, the cumulative annual revenue deficiency at UNS Gas is quite large. Since the rates UNS Gas charged are based on plant investment levels as of December 31, 2001, adjusted to reflect the Company's $30.7 million *negative* acquisition adjustment, there is an obvious need for adequate and timely rate relief at UNS Gas.

Q. Will the impact of growth and regulatory lag be as pronounced in future years?

A. Hopefully not. Although customer growth and plant investment are not forecasted to decrease anytime soon, the gap between the Company's embedded plant investment and incremental plant investment on a per-customer basis should narrow over time. As may be seen in the table below, plant investment on a per-customer basis has increased by 24% since the UNS Gas properties were acquired in August 2003. Over the next three years, this measure of plant investment is expected to increase by a slightly lesser amount of 19%. This table is similar to the one provided on page 22 of my Direct Testimony, but has been updated to reflect actual results for 2006 and the Company's current outlook for customer growth and capital spending.

	Net Plant ($ Millions)	Customers	Investment per Customer
Aug. 2003	$138	127,616	$1,081
Dec. 2004	$161	133,403	$1,207
Dec. 2005	$177	138,797	$1,278
Dec. 2006	$195	145,052	$1,344
Dec. 2007 (Forecast)	$225	150,965	$1,490
Dec. 2008 (Forecast)	$249	158,442	$1,572
Dec. 2009 (Forecast)	$267	166,456	$1,604
% Change 2003-2006	41.3%	13.7%	24.3%
% Change 2006-2009	36.9%	14.8%	19.3%

Q. Have the major credit rating agencies commented on the impact of growth and regulatory lag on gas distribution utilities?

A. Yes. All of the major credit rating agencies (Moody's, Standard & Poor's and Fitch) have commented on the need for timely cost recovery in rates and the impact of large capital spending requirements on gas utilities. Most noteworthy are two articles published by Moody's and Standard & Poor's. In a 2004 report entitled "Comparative ROE Attributes of US Local Gas Distribution Companies," which is attached as Exhibit KCG-11 to my Rebuttal Testimony, Moody's had the following observations:

> The single most common determinant as to whether a company met or exceeded its allowed ROE was the degree of regulatory lag and the timeliness of capital expenditure and cost recoveries. Companies growing very quickly or having protracted negotiations with their regulators tended to fare more poorly than those growing more slowly

> or able to obtain specific provisions for timely rate relief. (See page 1 of Exhibit KCG-11.)
>
> The consequence of recurring regulatory lag is that companies often find themselves in an increasingly negative free cash flow position. In addition, companies on a fast growth track have the problem accentuated and invariably find themselves having to issue debt to fund the deficits in operating cash flows which over time, increase leverage to higher levels and undermine a company's credit metrics. (See page 3 of Exhibit KCG-11.)

In a 2006 report entitled "Key Credit Factors for U.S. Natural Gas Distributors," which is attached as Exhibit KCG-12 to my Rebuttal Testimony, Standard & Poor's made the following comment:

> High growth within a service territory due to population influx and new construction could lead to an LDC's (local distribution company) greater profitability or rate stability. However, as evidenced by Southwest Gas' struggles, high growth sometimes cuts both ways. Arizona and Nevada benefit from rapid population growth, but the slow pace of regulatory rate adjustments acts as a drag on Southwest Gas' financial ratios because revenues fail to adequately compensate the LDC for its growth capital expenditures on a timely basis. (See page 5 of Exhibit KCG-12.)

Q. At page 8 of her Direct Testimony, Ms. Diaz Cortez states that "...rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery." Do you agree with that statement?

A. If she is referring to a large multi-year construction project on which an allowance for funds used during construction ("AFUDC") is being accrued, then I would generally agree with her statement. However, in the case of UNS Gas, where the CWIP balance is comprised of many short-lived construction projects, I do not agree. As pointed out in my Direct Testimony, including the $7.2 million test-year balance of CWIP in rate base would provide the Company with an additional $1.5 million of pre-tax earnings and cash flow. Although this estimate has since been lowered to $1.3 million per year after further review, this contribution to earnings still far exceeds the $285,378 of AFUDC recorded by UNS Gas for all of 2006. And since nearly all of the $7.2 million test-year balance of CWIP has already been transferred to plant in service, additional accruals of AFUDC on this test-year balance will be immaterial. In light of the earnings shortfall illustrated in Exhibit KCG-10, and the lack of future AFUDC accruals on the test-year balance of CWIP, it is readily apparent that the inclusion of CWIP in rate base affects the level of earnings realized by UNS Gas. This rate treatment also provides an additional source of cash flow needed to fund capital expenditures, a benefit that non-cash accruals of AFUDC do not provide.

Q. Should the Company be allowed to continue accruing AFUDC on new construction projects even if CWIP is allowed in rate base?

A. Yes. It is my understanding that accounting guidelines published by the FERC require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals. While it would be reasonable to apply this guideline to long-term construction projects for which CWIP has been included in rate base, the majority of projects included in UNS Gas' test-year CWIP balance were short-term in nature. Given that only a small amount of AFUDC has been accrued on the test-year balance of CWIP, it would be unfair to require UNS Gas to cease accruing AFUDC on $7.2 million of CWIP on an ongoing basis, year after year. For this reason, should the Commission grant the Company's request to include CWIP in rate base, UNS Gas requests that the Commission include language in the final order that authorizes the Company to continue accruing AFUDC on all eligible construction projects.

Q. At page 9 of her Direct Testimony, Ms. Diaz Cortez states that "The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit." Do you agree with that statement?

A. No. Although the timing of UNS Gas' next rate filing will depend on numerous factors, the earnings and cash flow benefit associated with CWIP in rate base should help to extend the period between this rate case and the next rate filing. As I pointed out in my

Direct Testimony, rate case preparation is very costly and time consuming for a company the size of UNS Gas, and an extension of time between rate filings is beneficial to both the Company and its customers.

Q. At page 10 of her Direct Testimony, Ms. Diaz Cortez characterizes one of the Company's arguments on CWIP in rate base as being "disingenuous at best." What is your response to this characterization?

A. It is unfortunate that Ms. Diaz Cortez portrays the Company as being disingenuous. Customers are receiving the full benefit of the negative acquisition adjustment, just as promised in 2003, and will continue to receive that benefit until the negative acquisition adjustment is fully amortized. Additionally, customers will have received the full benefit of a four-year rate moratorium, despite the obvious burden that rate freeze has imposed on UNS Gas. What could not be foreseen in 2003, however, was the significant amount of capital required to meet customer growth and system improvement needs. Similarly, it was difficult to predict the future impact of regulatory lag on UNS Gas. In short, the Company had no way of knowing in 2003 that it would need to request CWIP in rate base in 2006. Sadly, it appears that Ms. Diaz Cortez views this as an attempt by the Company to take back part of the benefit associated with the negative acquisition adjustment. By referring to the existence of a large negative acquisition adjustment in this rate case, the Company is simply pointing out a fact that cannot be ignored when discussing the need for timely and adequate rate relief.

Q. In excluding CWIP from rate base, Ms. Diaz Cortez made a $7.2 million downward adjustment to rate base. Did she make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Gas related to the $7.2 million CWIP balance was $4,158,264. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Ms. Diaz Cortez should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, the result is to penalize UNS Gas for carrying a balance of CWIP at the end of the test year.

Q. Did Ms. Diaz Cortez address the Company's alternative proposal for a post-test year adjustment to rate base?

A. No, I did not find any reference to that proposal in her Direct Testimony. It is possible that her views on post test-year plant adjustments are similar to the views she expressed on CWIP in rate base. However, it should be noted that as of December 31, 2006, $6.8 million of the test year balance of CWIP had already been closed to plant in service and was providing service to UNS Gas customers.

Q. Does that conclude your rebuttal to the Direct Testimony of Ms. Diaz Cortez?

A. Yes, it does.

IV. <u>REBUTTAL TO STAFF WITNESS DAVID C. PARCELL.</u>

Q. Mr. Grant, could you summarize your view of the Direct Testimony filed by Mr. David Parcell on behalf of the Commission Staff?

A. Yes. The allowed ROE recommended by Mr. Parcell understates the cost of equity to UNS Gas by a substantial margin. This is due primarily to the conclusions he reached as a result of his CAPM analysis and comparable earnings approach, as well as to his dismissal of Company-specific risk factors at UNS Gas. Mr. Parcell also failed to consider these Company-specific risks in rejecting the Company's proposed capital structure, and relied upon balance sheet data for a group of higher leveraged *electric* utilities in making his ultimate recommendation. In rejecting the Company's request for

CWIP in rate base, Mr. Parcell mistakenly assumed that UNS Gas receives its financing based on the credit quality of UniSource Energy Corporation ("UniSource Energy"), and not on the "...situation of the Company itself." Additionally, other than a hypothetical interest coverage test that failed to consider the large reduction to the Company's rate proposal being recommended by Staff, Mr. Parcell did not present any quantitative financial analysis on the subject of financial integrity.

Q. Please elaborate on Mr. Parcell's cost of equity analysis.

A. Certainly. Regarding his DCF analysis, I agree with the view he expressed on page 27 of his Direct Testimony where he described current financial conditions driving DCF results to historically-low standards. In recognition of this, he used the upper end of his DCF analysis for purposes of estimating the cost of equity for UNS Gas. The upper end of his DCF range (9.25% to 10.5%) is comparable to the DCF results I obtained for the comparable company group in my Direct Testimony (9.1% to 10.5%).

Regarding Mr. Parcell's application of the CAPM, I would note that the range of results obtained for the companies in his comparison group of combination gas and electric utilities ranged from 9.0% to 12.2%, while the results he obtained using my comparable company group ranged from 9.0% to 12.5% (see Schedule 9 attached to his Direct Testimony). However, due to his reliance on mean and median values, the range he ultimately relied upon was 9.5% to 10.25%. By contrast, the range I obtained from my comparable company CAPM analysis was 9.9% to 11.7%, using a risk-free rate of 5.3% and an equity risk premium of 7.1%. This difference is largely attributable to Mr. Parcell's use of a lower risk-free interest rate (based on updated bond market data) and his use of a significantly lower market risk premium.

Q. Please comment on the equity risk premium used by Mr. Parcell in his CAPM analysis.

A. Mr. Parcell used an equity risk premium of 5.9%, which is based on the difference between historical returns on large stocks and long-term government bonds using both arithmetic and geometric mean returns. By contrast, the 7.1% equity risk premium used in my CAPM analysis was based solely on arithmetic mean returns. Because an arithmetic mean return reflects the mathematical average of historical returns realized over each discrete 12-month period, the use of a risk premium based on arithmetic mean returns is more appropriate when calculating a discount rate (*i.e.*, the cost of capital) that is used for discounting future annual cash flows (*i.e.*, dividends and capital gains). By contrast, the geometric mean return, which equals the compound average return earned over a multi-year period, is appropriate for reporting and comparing returns over historical time periods. Since the geometric mean is always less than the arithmetic mean for any series of data having non-constant annual rates of return, Mr. Parcell's application of the CAPM serves to inappropriately understate the cost of equity capital for the companies he examined.

The use of arithmetic mean returns versus geometric mean returns is specifically addressed by Ibbotson Associates, the publisher of historical financial return data cited in the Direct Testimony of Mr. Parcell and Mr. Rigsby as well as in my own Direct Testimony. On page 77 of the 2006 Yearbook (Valuation Edition) published by Ibbotson Associates, the following commentary is provided:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the

> sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

Q. Did Mr. Parcell also conduct a comparable earnings analysis?

A. Yes, he did. As reflected in the table on page 32 of his Direct Testimony, he indicated that the average historical earned ROE for the proxy groups he examined ranged from 10.7% to 11.8%, while the average prospective ROE ranged from 10.0% to 11.7%. However, as indicated on pages 33 and 34 of his Direct Testimony, Mr. Parcell cites historically high market-to-book ratios for utilities as a reason for recommending a 10.0% cost of equity based on this analysis. While I do not dispute the average ROE data cited by Mr. Parcell, I do take issue with his conclusion that a 10% cost of equity is reasonable based on this data. The fact that market-to-book ratios for regulated utilities routinely exceed a value of 100% does not diminish the fact that utilities such as UNS Gas must compete for equity capital with other utilities. If earned ROEs for utilities are in the range of 10-12% on both a prospective and historical basis, it is unreasonable to assume that any utility would be able to successfully compete for equity capital with an allowed ROE at or below the low end of this range. Stated another way, if Mr. Parcell's objective is to achieve a market-to-book ratio of 100% when the industry average ratio is closer to 180%, the ability of UNS Gas to successfully compete for equity capital would be substantially reduced.

Q. Do you have any further comments regarding Mr. Parcell's cost of equity analysis?

A. Yes. For the reasons described above, I believe that his recommended cost of equity is low relative to the actual cost of equity for the proxy groups he examined. In addition, Mr. Parcell also failed to account for the Company-specific risk factors that serve to increase the cost of equity capital for UNS Gas relative to the proxy group companies. For example, on page 38 of his Direct Testimony Mr. Parcell dismisses the small size of UNS Gas because it is owned by UniSource Energy. But he offers no reason why

UniSource Energy would be more willing than other investors to accept the risk of investing in a small utility. Mr. Parcell also dismisses the financial impact of growth on the Company by citing a report published by Standard & Poor's in 2003, a point in time when the effects of growth and regulatory lag on UNS Gas had yet to be fully appreciated. By dismissing these Company-specific risk factors, as well as other risk factors discussed in my Direct Testimony, Mr. Parcell has recommended an allowed ROE for UNS Gas that is well below the Company's actual cost of equity.

Q. Did Mr. Parcell agree with the Company's proposed capital structure for UNS Gas?

A. No, he did not. Instead of using the proposed hypothetical capital structure consisting of 50% common equity and 50% long-term debt, which RUCO witness Rigsby also found to be reasonable, Mr. Parcell used the historical test year capital structure consisting of approximately 45% common equity and 55% long-term debt.

Q. At page 18 of his Direct Testimony, Mr. Parcell states that "...it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities." Did Mr. Parcell provide such an evaluation of the Company's capital structure?

A. Yes, but only to a limited extent. At page 20 of his Direct Testimony he compares the equity ratio of UNS Gas to the equity ratios for two groups of utilities, neither of which is specific to the gas distribution industry. The equity ratios for these groups are significantly lower than the ratios identified in my Direct Testimony as well as that of Mr. Rigsby for gas distribution utilities. Also, I could not find any discussion in Mr. Parcell's Direct Testimony regarding why his recommended capital structure was appropriate relative to the level of business risk faced by UNS Gas.

Q. At page 36 of his Direct Testimony, Mr. Parcell concludes that his cost of capital recommendation provides the Company with "a sufficient level of earnings to maintain its financial integrity." Do you agree with his conclusion?

A. No, I do not. No attempt was made by Mr. Parcell to determine whether or not the Company could actually earn his recommended ROE of 10.0% or his overall ROR of 8.12%. Based on all of the adjustments made by Staff, the recommended rate increase for UNS Gas is only $4.7 million, or 49% of the Company's requested increase. If Staff's recommendations were accepted in their entirety, the Company would have no opportunity to actually earn the ROR recommended by Mr. Parcell. As a result, the pre-tax interest coverage calculation presented on Schedule 14 attached to his Direct Testimony represents nothing more than a hypothetical example. While I appreciate Mr. Parcell's intent, which is to examine the impact of his recommendations on the Company financial integrity, it does not take into account the numerous adjustments made by other Staff witnesses that serve to limit any improvement in the Company's earnings and cash flow.

Q. Did Mr. Parcell make any other observations regarding the Company's financial integrity?

A. Yes. At pages 16 to 17 of his Direct Testimony he addresses the Company's ability to attract capital. In this section of his Direct Testimony, he states that it is not "necessary" for UNS Gas to include CWIP in rate base in order to attract capital. In support of his conclusion, he cites rating agency reports that refer to UNS Gas as "low risk." However, the only rating agency report specifically cited by Mr. Parcell that refers to UNS Gas is a report by Standard & Poor's published in 2003. This report is over three years old and was written at a time when natural gas prices were much lower and when the cumulative effects of growth and regulatory lag on UNS Gas had not yet materialized. Mr. Parcell also makes reference to the supposed ability of UNS Gas to attract financing based on the credit quality of UniSource Energy. However, this assumption is incorrect, since no guarantees of UNS Gas debt obligations have been issued by UniSource Energy, TEP, or any other corporate affiliate other than UniSource Energy Services ("UES"), the parent company of UNS Gas and UNS Electric.

Q. Do you agree with Mr. Parcell's conclusion that CWIP is not necessary for the attraction of capital by UNS Gas?

A. Over the short-run, I agree that UNS Gas could continue to attract capital without having CWIP in rate base. However, what Mr. Parcell does not address is the ability of the Company to attract capital on *reasonable terms*. Facing the prospect of below-market returns on equity, high capital spending requirements, and no prospect of common dividend payments, it would be difficult to convince any prospective equity investor to commit additional equity capital to UNS Gas. Under these circumstances, the Company would have to rely more heavily on debt capital to fund its capital spending needs. With this additional debt leverage comes additional lending risk, and the cost of debt to UNS Gas would likely increase significantly. Additionally, it should be recognized that the Company's borrowing capacity is not infinite. So while Mr. Parcell is correct that additional capital could probably be attracted over the short-run, the cost of this capital and long-term effects on the Company cannot be ignored.

Q. Is the calculation of a hypothetical interest coverage ratio sufficient to determine whether or not UNS Gas will be able to attract capital on reasonable terms?

A. No, it is not. In order to assess the real financial impact of Staff's recommendations, it is necessary to examine the Company's financial forecast and to adjust that forecast for the reduced level of rate relief recommended by Staff. Financial forecasts for UNS Gas were provided to Staff on at least two occasions through the discovery process, along with supporting calculations of key financial indicators. While I am well aware of the complexities involved in adjusting financial forecasts, it is a relatively easy task to assess the impact of a reduced rate recommendation on certain key financial measures such as net income, operating cash flow and return on equity.

Q. How does Staff's recommended rate increase impact key financial indicators forecasted for UNS Gas?

A. Staff has recommended a $4.9 million reduction to the Company's requested level of rate relief based on test-year sales levels. Adjusting this figure for two additional years of sales growth, this difference in annual revenues would grow to approximately $5.3 million by 2008. On an after-tax basis, this represents a decrease of approximately $3.2 million in net income and operating cash flow relative to the Company's base case financial forecast for 2008, the results of which were summarized in Exhibit KCG-9 attached to my Direct Testimony. In that base case forecast, the Company projected net income of $10.0 million, a return on average common equity of 10.0%, and operating cash flow of $21.7 million in 2008. As reflected in the following table, the Company's financial forecast would reflect a projected net income of only $6.8 million, a return on average common equity of approximately 6.8%, and operating cash flow of $18.5 million in 2008 when adjusted for the reduced level of rate relief recommended by Staff.

($ millions)	Company Forecast (Exhibit KCG-9)	Adjustment	Forecast Adjusted for Staff Proposal
Net Income	$10.0	($3.2)	$6.8
Return on Equity	10.0%	x (6.8 / 10.0)	6.8%
Operating Cash Flow	$21.7	($3.2)	$18.5

If Mr. Parcell's hypothetical 10.0% earned ROE on Schedule 14 of his Direct Testimony is replaced with the 6.8% adjusted ROE from the table above, the pre-tax coverage ratio calculated by Mr. Parcell would fall from 3.04X to 2.39X. According to Mr. Parcell's

Exhibit DCP-1, Schedule 14 in his Direct Testimony, a minimum coverage ratio of 2.4X is required to achieve a minimum "BBB" investment-grade credit rating.

Q. Does UNS Gas have a more recent base case financial forecast that can be used to evaluate the prospective financial condition of the Company?

A. Yes. Exhibit KCG-13 provides an updated summary of projected key financial indicators. This forecast assumes that the Company's rate request is granted in full, and has been updated to reflect actual results for 2006 and to incorporate new capital spending and operating budget projections for 2007 and beyond. As may be seen on page 1 of that exhibit, operating cash flow was abnormally high in 2006 due to the recovery of the Company's large PGA bank balance.

Q. Does UNS Gas have a similar financial forecast that incorporates Staff's recommended level of rate relief?

A. Yes. The key financial indicators for that forecast may be found in Exhibit KCG-14. Although the forecasted results for 2008 are not the same as estimated in the table above, they are very similar despite the use of updated forecast assumptions. Specifically, forecasted values for net income, return on average equity and operating cash flow are $6.9 million, 7.4% and $17.8 million, respectively.

Q. Do you have any comments regarding the financial forecast summarized in Exhibit KCG-14?

A. Yes. As may be seen on page 1 of that exhibit, the Company's earned ROE is expected to improve only slightly and is not expected to come close to Staff's recommended ROE in future years. Likewise, operating cash flows are expected increase only slightly over 2005 test year levels. As may be seen on page 2, the percentage of capital expenditures funded with internal cash flow is forecasted to remain quite low over the next three years, indicating a large need for additional capital. Absent additional equity contributions, the Company's borrowings are forecasted to increase significantly. As may be seen on pages 3 and 4, this additional borrowing serves to limit any balance sheet improvement at UNS Gas and contributes to weak cash flow coverage ratios relative to industry median values. With reduced borrowing capacity, the Company's ability to finance unexpected increases in the PGA bank balance, potential collateral calls by wholesale gas providers, or unanticipated capital expenditures would be greatly diminished. Under such circumstances, it would be difficult for the Company to attract additional capital on reasonable terms.

Q. Do you have any other comments regarding Mr. Parcell's cost of capital recommendations?

A. Mr. Parcell's cost of capital recommendations – specifically his recommendations on cost of equity and capital structure – will put UNS Gas at a disadvantage as far as being able to attract capital on reasonable terms. If Staff's recommended ROE and overall rate proposal are accepted, the financial integrity of UNS Gas will suffer and its ability to improve its capital structure will be adversely affected.

Q. Does that conclude your rebuttal to the Direct Testimony of Mr. Parcell?

A. Yes, it does.

V. <u>REBUTTAL TO STAFF WITNESS RALPH C. SMITH.</u>

Q. Mr. Grant, could you please summarize your view of the Direct Testimony filed by Mr. Ralph Smith on behalf of the Commission Staff?

A. Yes. Similar to Ms. Diaz Cortez, Mr. Smith rejects the Company's request for CWIP in rate base largely on philosophical grounds. Mr. Smith also makes reference to a "burden of proof" that UNS Gas has not met, but does not offer any description of what this standard might be. Although he recognizes that the inclusion of CWIP in rate base is up to the discretion of the Commission, he offers several reasons why Staff does not recommend this ratemaking treatment.

Q. What specific reasons are offered by Mr. Smith in rejecting the Company's request for CWIP in rate base?

A. On page 9 of his Direct Testimony, Mr. Smith offers four reasons for rejecting the Company's request for CWIP in rate base. The first two reasons, that CWIP in rate base is not normally allowed by the Commission, and that projects included in the test year CWIP balance were not yet in service as of the test year, are merely statements of the obvious. The third reason, which relates to the need to recognize revenues produced by projects included in the CWIP balance, has already been addressed in my rebuttal of Ms. Diaz Cortez. The fourth and final reason, that the Company has made no specific enforceable commitment to a rate case moratorium period, erroneously assumes that UNS Gas is in a position to make such a commitment prior to knowing how much of a rate increase it will receive in this proceeding.

The most meaningful reason offered by Mr. Smith for rejecting the Company's request is only mentioned in passing, on lines 8 to 9 at page 9 of his Direct Testimony. Here he refers to the Company's failure to meet a "burden of proof" showing why it requires this ratemaking treatment. However, I could not find a description anywhere in Mr. Smith's Direct Testimony of what this burden of proof entails or what evidence the Company would need to present to meet this burden. Presumably it is a standard based on the ability to attract capital, the subject addressed by Mr. Parcell at pages 16 to 17 of his Direct Testimony. The only other statement I could find regarding the Company's failure to meet this burden of proof appears at page 10, lines 23-25 of Mr. Smith's Direct Testimony, where he states that "In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base."

Q. In excluding CWIP from rate base, Mr. Smith made a $7.2 million downward adjustment to rate base. Did he make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Gas related to the $7.2 million CWIP balance was $4,158,264. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Mr. Smith should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, the result is to penalize UNS Gas for carrying a balance of CWIP at the end of the test year.

Q. Did Mr. Smith consider the Company's alternative request for including post-test year plant additions in rate base?

A. Yes, he did. However, he did not have any additional reasons to offer for rejecting this ratemaking alternative.

Q. What would be the impact on Staff's proposed revenue requirement if Staff included either a post-test year adjustment to rate base or removed the customer advances related to the test year CWIP balance?

A. Including a $6.8 million post-test year adjustment to rate base would increase Staff's proposed revenue requirement by approximately $1.1 million. Removing $4.2 million of customer advances from rate base would increase Staff's proposed revenue requirement by approximately $500,000.

Q. Did Mr. Smith adjust the cost of capital recommended by Staff witness Parcell before applying it to Staff's fair value rate base?

A. Yes, he did. Consistent with prior Commission practice, he lowered the overall ROR applied to fair value rate base in order to achieve the same level of operating income calculated using Mr. Parcell's cost of capital and Staff's original cost rate base.

Q. Is this ROR adjustment the same as addressed in the recent Arizona Court of Appeals ruling involving Chaparral City Water Company, the Commission and RUCO?

A. Yes. My non-legal understanding of that ruling dated February 13, 2007, is that the Arizona Court of Appeals found that Staff's determination of operating income ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

Q. What action do you recommend in light of this court ruling?

A. I recommend that the Commission apply the weighted cost of capital (or overall ROR) to the Company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than proposed by the Company, UNS Gas would still be limited to the original rate relief sought in the Company's rate application.

Q. Do you have any other comments on Mr. Smith's Direct Testimony?

A. No. Most of his concerns regarding CWIP in rate base are similar to the concerns voiced by Ms. Diaz Cortez, which I have already addressed earlier in my Rebuttal Testimony.

Q. Does that conclude your rebuttal to Mr. Smith's Direct Testimony?

A. Yes, it does.

VI. CONCLUSION.

Q. Mr. Grant, do you have any concluding testimony?

A. Yes, I do. For the reasons stated in my Direct Testimony and reiterated here in my rebuttal testimony, I recommend that the Commission adopt an allowed ROE of 11.0% and an overall ROR of 8.80% for UNS Gas. Additionally, in light of the recent Arizona Court of Appeals ruling regarding the use of fair value rate base in setting rates, I recommend that the Commission apply this 8.80% ROR to the Company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than originally proposed by the Company, UNS Gas would still be limited to the rate relief sought in the Company's rate application.

Contrary to the positions taken by Staff and RUCO, the inclusion of test year CWIP in rate base is needed to preserve the Company's financial integrity. The Company's net plant investment has increased by 41% since the August 2003 acquisition of gas properties from Citizens Communications Company, and is expected to increase by another 37% over the next three years. This growth in net plant investment creates a huge demand for capital and an obvious need for timely and supportive rate relief. I believe I have provided ample evidence and UNS Gas has therefore met whatever burden it may have to justify the inclusion of CWIP in rate base and why doing so is also fair and reasonable. In the alternative, should the Commission decide not to include CWIP in rate base, UNS Gas urges the Commission to allow a post test-year adjustment to rate base to include plant already placed into service. As of December 31, 2006, this amount represented $6.8 million, or approximately 94% of the $7.2 million test year CWIP balance.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

EXHIBIT

KCG-10

UNS Gas, Inc.
Impact of 2006 Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Fixed Costs from 2006 Plant Additions

Net Utility Plant at 12/31/06	$195,131,000
Less: Net Utility Plant at 12/31/05 (end of test year)	($177,420,000)
Increase in Net Plant for Year Ended 12/31/06	$17,711,000
x Fixed Cost Factor	17.23%
Increase in Annual Fixed Costs	**$3,052,225**

Derivation of Fixed Cost Factor:

	% Capital Structure	Cost	Weighted Cost	Tax Factor	Pre-Tax Cost
Equity Capital	50.00%	11.00%	5.50%	1.637	9.00%
Debt Capital	50.00%	6.60%	3.30%	1.000	3.30%
	100.00%		8.80%		12.30%

Composite Depreciation Rate	2.73%
Composite Property Tax Rate	2.20%
Annual Fixed Cost of Plant Additions	17.23%

UNS Gas, Inc.
Impact of 2006 Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Delivery Revenues from 2006 Customer Additions

	Residential	Small Commercial	Small Public Authority	Industrial & Other	Total
Customers at 12/31/06	132,534	11,416	1,059	43	145,052
Less: Customers at 12/31/05 (test year end)	(126,682)	(11,017)	(1,054)	(44)	(138,797)
Increase in Customers for Year Ended 12/31/06	5,852	399	5	(1)	6,255
x Use per Customer (normalized test year)	568	2,657	5,510	N/A	706
Increase in Annual Therm Sales	3,325,295	1,060,236	27,550	-	4,413,081
x Average Delivery Revenues per Therm (test year)	$0.4480	$0.2941	$0.2621	N/A	$0.4099
Increase in Annual Delivery Revenues	$1,489,800	$311,773	$7,221	-	**$1,808,794**

Increase to Annual Revenue Deficiency from 2006 Plant and Customer Additions

Increase in Fixed Costs	$3,052,225
Less: Increase in Delivery Revenues	($1,808,794)
Increase to Revenue Deficiency	**$1,243,431**

EXHIBIT

KCG-11

Special Comment

July 2004

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Edward Tan	1.212.553.1653
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John Diaz	

Comparative ROE Attributes of US Local Gas Distribution Companies

Summary Opinion

- Moody's reviewed its portfolio of local gas distribution companies (LDCs) in search of the characteristics that differentiated those companies that either met or exceeded their allowed rates of equity return (ROE) from its utility commissions with those that did not.
- We found a positive correlation between ROEs and credit ratings. Companies that either met or exceeded their allowed rates of equity return (ROE) were more likely to have higher credit ratings, were concentrated in urban areas, and focused their operations in a single-state jurisdiction with more mature customer profiles. In addition, they tended to be larger companies with larger total number of customers and delivered the most gas volumes.
- Companies performing well also tended to have formal weather normalization clauses (WNC) in place that have helped to steady their operating performance and credit metrics which resulted in the higher credit ratings.
- The single most common determinant as to whether a company met or exceeded its allowed ROE was the degree of regulatory lag and the timeliness of capital expenditure and cost recoveries. Companies growing very quickly or having protracted negotiations with their regulators tended to fare more poorly than those growing more slowly or able to obtain specific provisions for timely rate relief.
- Companies having significant amounts of goodwill were at a distinct disadvantage compared with their peers, as they typically are not allowed to earn returns on the premium portion of acquisition assets.
- While in several respects LDCs were equally concerned with improving operating efficiencies through automation, centralizing shared services and implementing various programs for workforce reduction as a means to contain the ever-rising costs of salary, pension and medical benefits, the ones that met or exceeded their allowed ROEs had lower operating expense to employee ratios.

Introduction

As LDCs have embarked on a "back to basics" strategy, overall efficiency of operations and returns on capital employed resurface as key factors in the rating process. We therefore analyzed our portfolio of 32 issuers with a view toward identifying the key factors that separate the LDCs' ability to achieve or exceed their allowed returns. We define "realized" as those gas LDCs that had either met or exceeded their regulated allowed rates of equity return (ROE) on a consistent basis during the past three fiscal years ending with 2003. Where no specific rates were stipulated, Moody's still recognized a company as "realized" if they achieved an ROE of at least 10% during the past three years. Companies that were within one percentage point of making their allowed ROEs were deemed to have met their targets. Those companies not able to realize their allowed ROEs are designated in this study as "not-realized."

From this point of demarcation, the analysis then moves on toward identifying the various factors that may have contributed toward an LDC's success. Some of these points might be intuitive (size and density of population served), while others were more empirical (variances in regulatory lag).

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By analyzing the attributes of these realized LDCs, one could discern a pattern for likely future success that could serve as a guide for management focus on key factors for improving their returns as well as assisting investors with differentiating the companies that have stronger operating performance.

While almost all issuers approached were able to respond, some of their reports had to be excluded from consideration as they were compiled in a manner which made comparisons difficult. For example, in cases where a company co-mingled electric and gas utility data, the responses were deleted as the focus of this study is only on gas LDCs. It is also important to recognize that in a few cases issuers have asked that their names and figures be kept confidential and as a result, their responses were included as part of the general study without any attempts at identification or attribution. Altogether, Moody's identified 15 LDCs that either met or exceeded their allowed ROEs while 17 others did not.

Not surprisingly, the realized LDCs (henceforth known as the R-class) tended to have more "A" credit ratings relative to "Baa" credit ratings than those companies that did not meet their allowed ROEs (known as the NR-class). In fact, the ratio of issuers rated "A" vs. those rated "Baa" is 2.75 for the R-class compared with 1.125 for the NR-class.

Focused Critical Mass

The R-class names also tend to have the largest number of gas customers, deliver the most volumes of gas as measured in Bcf, are focused in a single-state jurisdiction and are more likely to be located in urban[1] areas with a more mature customer profile exhibiting slower but steady growth as opposed to newer and rapid growth.

The average number of R-class customers is approximately 1.1 million compared with the 653 thousand average for the NR-class, while the volume of R-class delivered gas averages 222Bcf compared with 114Bcf for the NR-class.

The overwhelming majority of R-class LDCs are focused on a single-state vs. multiple states (11:4) compared with the NR-class LDCs (6:11) and are more likely to be operating in urban areas rather than rural (2.25 urban/rural ratio for R compared with 1.7 ratio for NR). Moreover, the average customer growth rate for the R-companies is 1.5%p.a. while that for the NR companies is 2.0%p.a. While different companies may experience different rates of customer growth, the ideal range appears to lie between 1.5%-3.0% p.a. Anything slower could hinder the generation of earnings growth to satisfy equity investors while anything faster could push up various cost factors which when combined with the sector's "regulatory lag" could compress a company's ROE and credit metrics.

The above numbers suggest that the profile of the R-companies are larger, more firmly established or entrenched in their single-state jurisdictions which tend to be more urban than rural and are growing at a slower but steady rate in comparison with the NR-companies. The single state focus and critical mass developed in key urban areas of the state appear to position these LDCs well for steady and successful growth. A good example of an R-company fitting this profile might be Southern California Gas Company (rated A2 Sr. Unsec.) with 5.4 million customers (growing at about 1% p.a.) delivering approximately 939Bcf of gas each year in the State of California with 97% of the company's operations concentrated in urban areas. Its authorized ROE for 2003 was 10.82% but it achieved 15.64% instead.

Impact of Weather

Moody's has taken the position for some time that gas LDCs are far better off having weather normalization clauses (or their equivalent) built into their basic rate designs (see Special Comment #76344 published in October of 2002 titled *Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversification And Warm Weather*). This opinion seems to be reinforced by the fact that nine of the 15 R LDCs have formally approved weather normalization clauses (WNC) or recognized weather mitigants built into their rate designs compared with only five out of the 17 LDCs that were NR.

Companies that do not have such WNC provisions for the majority of their customer base which did not make their target ROEs and cited warm weather as part of the reason include Cascade Natural Gas, SEMCO Energy, Southwest Gas Corporation and Vectren's Indiana Gas Company. In the case of Indiana Gas Company, the company estimates that a 1% annualized deviation from normal heating weather would impact pre-tax margins by $900,000, a condition which the company is presently attempting to rectify in its current rate filing through the introduction of a WNC feature.

One company in the R-class that was afflicted by warmer than normal winters and has since implemented a weather mitigation rate design is Laclede Gas Company. In its 10-Q filing for the six months ending March 31, 2004

1. *For purposes of this study, Moody's defines urban as any city or town that is served by the LDC's main gas line in a contiguous flow of proximity for 100,000 or more customers. Any number less is considered rural.*

when temperatures in its service area were 12% warmer than normal and 14% warmer than the same period last year, Laclede Gas Company states: "The magnitude of the effect of lower sales was smaller than would have previously been the case due to the impact of the fully-implemented weather mitigation rate design that produced higher margin revenue for the six months ended March 31, 2004, compared with the same period last year."

While various forms of weather mitigants are available to LDCs (weather insurance, weather derivatives, use of declining block rates), Moody's finds that WNC or their rate design equivalents are the most cost-effective means of protecting against warmer than normal weather conditions.

It is worth noting however, that the loss of gas volumes resulting from customer energy conservation (or improved efficiency ratings of customer home insulation and equipment) is a separate but growing factor in reducing LDC operating margins. Two companies that report meaningful reductions in gross margins on account of energy conservation by their customers in recent years are Public Service Company of North Carolina, Inc. (PSNC at 8%) and Questar Gas Corporation (7%). Altogether nine R-class companies and 10 NR-class companies report having suffered some degree of gross margins on account of gas conservation. Some companies are also building this factor into their volumetric rate designs or implementing "conservation" margin trackers to protect margins. These margin trackers allow LDCs to recover from customers a portion of gross margins lost on account of customer gas consumption declines resulting from their energy conservation measures.

Impact of Regulatory Lag

The most common explanation offered by LDCs for not being able to meet their allowed ROE is the impact of regulatory lag, especially as it affects the most significant component of cost, the depreciation, depletion and amortization portion resulting from capital expenditures. The average time frame for R-class LDCs to recover capital expenditure costs is over an average depreciable life of their assets of 374.5 months compared with 386.6 months for the NR-class companies. While this may not appear to make much of a difference in and of itself, it is noteworthy when combined with the fact that the faster growing NR-class companies appear to be more burdened with the "growth" component of capital expenditures as opposed to the "maintenance" capital expenditures which appear to be the focus of the more established R-class companies

The consequence of recurring regulatory lag is that companies often find themselves in an increasingly negative free cash flow[2] position. In addition, companies on a fast growth track have this problem accentuated and invariably find themselves having to issue debt to fund the deficits in operating cash flows which over time, increase leverage to higher levels and undermine a company's credit metrics.

In 2003 for example, the average growth capital expenditure for the R-class companies was $29.3 million compared with $43.8 million for the NR-class companies, which was 50% more. In absolute terms, the total growth capital expenditure for the R-class was $439 million compared with $701 million for the NR-class companies. In fact, the total number spent by the NR-class LDCs on growth capital expenditures was substantially higher than that spent by the R-class for each of the past five years under study. The average of the maintenance capital expenditures however, spent by the R-class is 42% higher at $59.3 million in 2003 compared with $41.8 million for the NR-class. The credit implications of this greater emphasis on growth capital expenditures on the part of NR companies is more evident when we also consider their lower free cash flows, gross cash flow to capital expenditures and retained cash flow to debt ratios compared with those of the R companies. When we consider the lower free cash flows and retained cash flow to debt ratios of the NR companies it is easier to understand why their credit metrics and credit ratings are relatively lower than those of the R companies. These weaker credit measures for the NR companies are apparent in the Appendix that follows this study.

This difference in emphasis in capital expenditure spending also appears to take on greater significance when the we take into account the comments made by at least three LDCs (National Fuel Gas, Questar Gas Company and Vectren for Indiana Gas Company) in stating that the maintenance expenditures (as in repairing leaks) tend to be recovered over a 12 month period rather than over the depreciable life of assets which is what is applied in the case of growth capital expenditures. If this difference in regulatory treatment is applied in other jurisdictions, it could help to explain why higher spending in growth capital expenditure programs over maintenance may hinder the NR-class LDCs from attaining their allowed ROEs. Companies that have cited capital expenditures related to infrastructure investments as a reason for regulatory lag leading to lower ROE include Southwest Gas Corporation, TXU Gas Company and Yankee Gas Services Company.

2. *Moody's defines free cash flow as gross cash flow from operations less capital expenditures, cash dividends and adjusting for deferred taxes. It serves as a measure of a company's ability to self-fund its operating needs.*

LDCs in at least four states are able to use forward test year data: California, Illinois, New York and Wisconsin, which tend to favor their LDCs and help close the gap caused by regulatory lag. Illinois in fact, allows for future test years as long as they do not exceed 24 months from the date of filing. Furthermore, Laclede Gas Company states that the Missouri legislature passed a recent law known as the Infrastructure System Replacement Surcharge that allows gas companies to file for a surcharge twice a year to recover depreciation expense, property taxes and a return on investment for all safety related or government mandated line replacements and relocations since the last rate case. Clearly LDCs in these states have better prospects for recovering their costs and reaching their target rates of return.

Impact of Goodwill

Another deterrent to achieving allowed ROEs is the regulatory treatment of goodwill which arises in acquisitions under purchase accounting. Most regulators do not allow any returns to be made on assets represented by goodwill, which oftentimes is funded through the issuance of debt that needs to be serviced each year as a fixed charge. Keyspan for example, mentions that a substantial portion of the shortfalls in the earned ROEs for their New England LDCs, Boston Gas and Colonial Gas, are attributable to the non-recoverability through basic rates on the goodwill incurred in connection with the acquisition of these properties in 2000.

Another example is the case of Wisconsin Gas Company. The Public Service Commission of Wisconsin does not recognize for ratemaking purposes the goodwill that was pushed down to Wisconsin Gas in its acquisition by Wisconsin Energy Corp. Consequently, while Wisconsin Gas has met its allowed rates of return on a regulatory basis, its US-GAAP ROEs adjusted for goodwill have been a fraction of its allowed levels. In adopting SFAS 142, Wisconsin Gas wrote down most of the goodwill that it incurred in its acquisition, in recognition of the high multiple that was paid in that merger and the level of returns that the utility is able to generate. This non-cash charge has brought Wisconsin Gas's US-GAAP ROEs closer to its allowed ROEs.

Workforce Reduction as a Means of Cost Control

Both R-class and NR-class LDCs have employed various means of workforce reduction as a means of containing rising costs of operation. This is done either unilaterally as part of a labor bargaining process or in conjunction with automating various repetitive functions such as in the use of automated meter readings in its gas operations.

While pension expense, medical expense and bad debt expense average 4%, 7% and 6% respectively, for both classes of LDCs as a percentage of total operating expense, workforce as a percentage of operating expense averages 48%. Companies are aiming to gradually reduce the number of employees in order to better contain not only wages and salaries but also the rises in costs of pension and medical benefits. In this regard, it is interesting to note that while the average number of employees for the R-class LDCs is greater than those in the NR-class (1,695 in 2003 to 1,042) perhaps because of their larger size, the total operating expense to employee ratio is lower ($122,180 to $142,109).

In terms of actual workforce reduction and the use of automation in operations, the reported figures are very similar between the two classes of LDCs. In the R-class, 12 companies report having taken actions to reduce the number of employees in recent years compared with 10 in the NR-class. While ten companies in each class report having automated various aspects of operations, few have specifically quantified their automated savings. One company however, that has made strides in the area of automated meter reading and been able to calculate the savings is The Peoples Gas Light and Coke Company (Peoples Gas). Peoples Gas states that it began its automated meter reading program in the mid-1990's with over 90% of all meters being automated by the end of 2002. The cost of meter reading in 1995 was $4.8 million for Peoples Gas and this cost fell to $2.2 million in 2002, representing a 54% reduction in this component of operating expenditures. Peoples Gas also noted additional savings from automated meter reading in the form of reduced estimated billing costs, billing error costs, non-registering meters, theft, and unauthorized use, which were not quantified. It appears that for some companies such as Peoples Gas which considers its customer base to be 100% urban, the benefits of automation could go farther given their greater customer concentration in the urban areas serviced by the company. This could be a case where customer concentration in urban areas might work towards the benefit of the LDCs located in large population centers.

The ability to control the number of employees is one key to controlling expenses. It stands to reason that companies growing the fastest would have the greatest pressures on rising employee count and employee benefits, which are more difficult to control than those companies experiencing slower growth. LDCs that have cited workforce restructuring charges or rising pension and medical expenses as special challenges in meeting their allowed ROEs include Cascade Natural Gas Corporation and Yankee Gas Services Company.

Conclusion

In its study of LDC ROE attributes, Moody's finds that the portfolio of companies could be divided into two approximately equal camps, those that meet or exceed their allowed ROEs and those that do not. Those companies that do realize their allowed ROEs (R-class companies), have a higher proportion of "A" credit ratings, tend to be focused in one-state jurisdictions and operate more often in urban areas compared with those with lower ROEs (NR-class companies). In addition, the R-class companies have a tendency to be larger, deliver greater volumes of gas, are more mature, experience slower or steady growth and concentrate on maintaining their operating systems rather than on expanding them into new service territories and are better positioned to control the rising operating costs of employee pension and medical benefits through workforce reduction programs. Their larger size and scope of operations tend to avail the R-class companies greater critical mass (especially when combined with urban concentration) and enable them to have better economies of scale in their operations.

Other factors that impact an LDC's relative success in achieving their allowed ROEs are the existence of weather normalization clauses or their rate design equivalents, the absence of goodwill from prior acquisitions and the widespread use of automation and central shared services to reduce duplication of functions at the field divisions. Finally, a progressive and supportive regulatory environment would certainly help companies achieve their earnings goals more easily. Given the pervasive "regulatory lag" that permeates the industry, jurisdictions that permit the use of future test periods for cost recovery, especially capital cost recovery, would go a long way toward helping these companies attain their allowed rates of return on equity and help stabilize their credit metrics.

Companies that actively seek to promote growth could find themselves squeezed by a combination of high growth capital expenditures, rising workforce, rising costs of employee pension and medical benefits, which when superimposed with goodwill, the absence of cost effective weather protection and ongoing regulatory lag, could keep them from achieving their full allowed rates of return.

Atmos Energy Corporation currently attains their allowed ROE in most of their 15 regulatory jurisdictions that are largely rural and mature. However, the proportion of maintenance capital expenditures far outweigh those for growth capital expenditures and many of its jurisdictions employ weather protection in their rate designs. Moreover, its operating expense to employee and operating expense to gross margin ratios are considerably less than the average of the 32 LDCs analyzed. Also, Atmos has one of the lowest proportions of unionized workforce at 10% compared with the 54% average for the industry, which undoubtedly gives it significant leverage to affect cost controls in the employment and benefits areas. Moody's notes that Atmos recently agreed to acquire the assets of TXU Gas, a neighboring utility in a more urban, somewhat higher growth service territory. It remains to be seen how this major acquisition that would roughly double its assets would affect Atmos's efficiency.

It is by examining the particular circumstances of individual issuers in comparison with the norms of the industry that we could attain a better understanding of the factors that impact their overall operating performance as we incorporate these findings into the credit ratings. As LDCs re-focus on their core regulated business, Moody's will continue to monitor their key operating as well as financial metrics in the overall credit evaluation process.

Related Research

Special Comment

Negative Rating Trend For Local Gas Distribution Companies: Impact Of Diversification And Warm Weather, October 2002 (# 76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix

Chart 1

Customer Size and Volumes Distributed in BCF of Gas

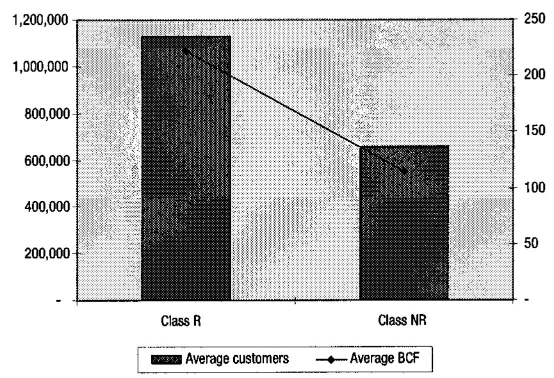
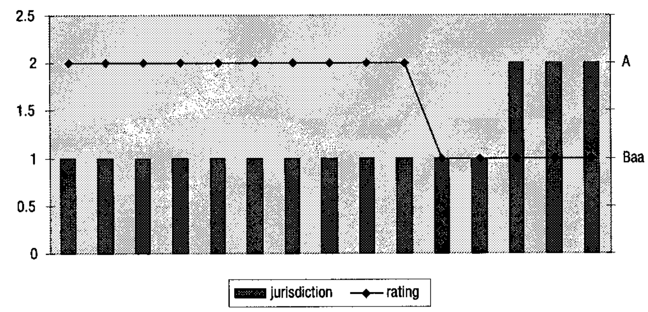


Chart 2

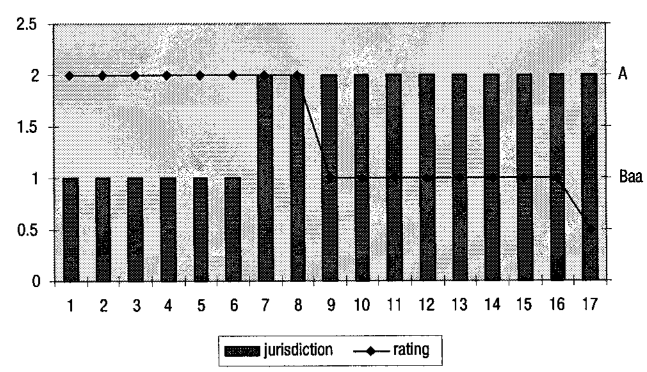
Class R Rating vs. Jurisdiction*



** Jurisdiction is graphed as "1" for single jurisdiction and "2" for multiple*

Chart 3

Class NR Rating vs. Jurisdiction*



** Jurisdiction is graphed as "1" for single jurisdiction and "2" for multiple*

Chart 4

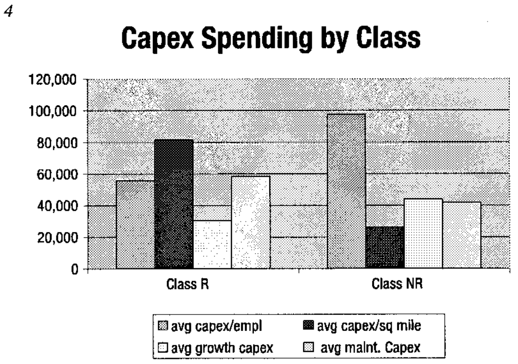


Chart 5

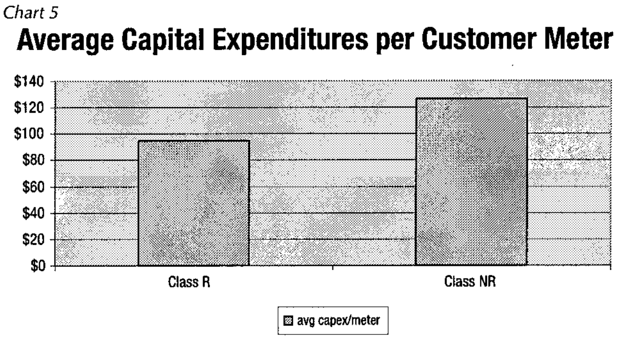


Chart 6

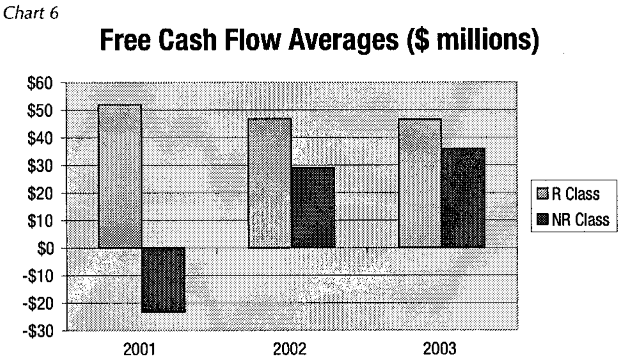


Chart 7

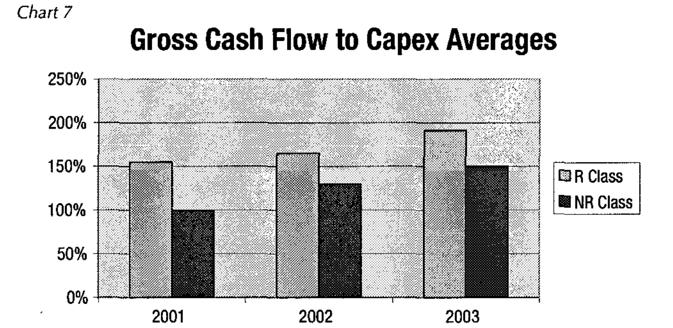
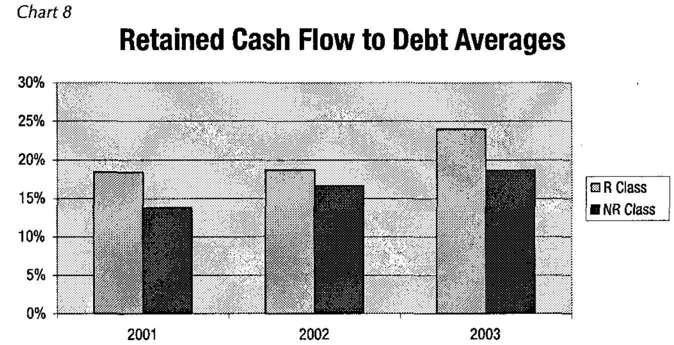


Chart 8



Selected Statistics for 2003

	% Rural customers	Urban customers	Number of customers	Annual Gas Volume (BCF)	5 yr avg customer growth	CAPEX Reg. Lag (Mos.)
Average Total	43%	57%	875,181	165	2.2%	381
Average R	**35%**	**65%**	**1,126,191**	**222**	**1.6%**	**374.5**
Average NR	49%	51%	653,703	114	2.2%	386.6

	GCF	Operating expense/ employee	Opex/ sq mile service area	Gross cash flow/ sq mile service area	Operating expense as % of gross margins	Workforce expense/ operating exp	Pension expense/ operating exp	Medical expense/ operating exp	Bad debt expense/ operating exp	% of Unionized workforce
Average Total	126,131	133,223	15,579	12,048	46%	48%	4%	7%	6%	54%
Average R	153,524	122,180	18,934	13,863	47%	49%	4%	7%	7%	55%
Average NR	101,961	142,109	12,643	10,460	46%	48%	4%	7%	6%	53%

$thousands	Growth Capex	Maintenance Capex	Total Capex	Capex per meter	Capex per employee	Capex per sq mile
Average Total	35,798	50,321	86,644	112	77,346	52,116
Average R	29,298	59,322	88,888	95	55,748	81,710
Average NR	43,806	41,883	84,664	126	97,595	26,221

EXHIBIT

KCG-12

STANDARD
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COMMENTARY
REPORT

Key Credit Factors For U.S. Natural Gas Distributors

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On its surface, analyzing U.S. gas distributors' credit quality would appear straightforward. After all, the core business simply involves distributing a commodity to mainly captive customers within a given service territory under a regulated environment. What could be more uncomplicated or have lower business risk? But, in reality, the universe of local natural gas distribution companies (LDCs) that Standard & Poor's Ratings Services rates has great credit diversity, as evidenced by ratings ranging from 'AA-' to 'BB-'.

Thus, the business risk profile is a defining attribute of an LDC's creditworthiness, as is the case with any corporate issuer. In most cases, Standard & Poor's categorizes pure LDCs as having well above average ('1' and '2') or above average ('3') business profiles (business profiles are categorized from '1' (strong) to '10' (weak)). Nonregulated business segments outside the relatively low-risk gas distribution arena generally weaken a company's business risk profile.

Clearly, higher-risk activities pressure the consolidated profiles and often require stronger financial performance to merit the same rating as a pure LDC. ONEOK Inc. (BBB/Watch Neg/A-2), an extreme example, has gas gathering and processing and energy trading and marketing activities that account for roughly two-thirds of its business mix and elevate the company's business profile to '6'. The inherent volatility of ONEOK's higher-risk businesses dwarfs the relative stability of its regulated gas distribution operations and exposes the company to greater cash flow volatility.

We look at five broad categories when reviewing an LDC's business risk profile: regulation, markets and competition, operations, management, and diversified activities. Below, key factors are highlighted and specific LDCs are identified that demonstrate strong or weak characteristics along these lines.

The business risk profiles of 14 LDCs operating in the U.S. can be seen in table 1.

Table 1

U.S. Gas Distributors Comparison

Company	Rating	Business profile	Gas adjustment mechanism	Supply position	Storage capacity (%)	Hedging policy in place
AGL Resources Inc.	A-/Negative/A-2	4	Yes	4	35	Yes
Cascade Natural Gas Corp.	BBB+/Stable/—	2	Yes	3	25	Yes
New Jersey Natural Gas Co.	A+/Stable/A-1	2	Yes	2	60	Yes
Nicor Inc.	AA/Negative/A-1+	3	Yes	8	55	Yes
Northwest Natural Gas Co.	A+/Stable/A-1	1	Yes	1	58	Yes
ONEOK Inc.	BBB/Watch Neg/A-2	7	Yes	8	15	Yes
Peoples Energy Corp.	A-/Negative/A-2	5	Yes	6	60	Yes
Piedmont Natural Gas Co. Inc.	A/Stable/—	2	Yes	5	50	Yes
SEMCO Energy Inc.	BB-/Stable/—	5	yes	4	35	Yes
South Jersey Gas Co.	BBB+/Neg/—	3	Yes	2	40	Yes
Southern Union Co.	BBB/Negative/—	3	Yes	8	30	Yes
Southwest Gas Corp.	BBB-/Stable/—	3	Yes	6	10	Yes
UGI Utilities Inc.	BBB/Watch Neg/—	4	Yes	3	N.A.	Yes
WGL Holdings Inc.	AA-/Negative/A-1	3	Yes	4	30	Yes

N.A.—Not available.

Regulation

Table 2

Regulatory Comparison

Company	Weather normalization	Allowed ROE (%)	Earnings sharing	Regulatory protection of LDC finances
AGL Resources Inc.	Yes	11 to 11.5	Yes	No
Cascade Natural Gas Corp.	No	11 to 11.5	Yes	No
New Jersey Natural Gas Co.	Yes	> 11.5	Yes	No
Nicor Inc.	Yes	11 to 11.5	No	No
Northwest Natural Gas Co.	Yes	< 11	Yes	No
ONEOK Inc.	Yes	N.A.	No	No
People's Energy Corp.	No	11 to 11.5	No	No
Piedmont Natural Gas Co. Inc.	Yes	> 11.5	No	No
SEMCO Energy Inc.	No	11 to 11.5	No	No
South Jersey Gas Co.	Yes	< 11	Yes	No
Southern Union Co.	No	< 11	Yes	Yes
Southwest Gas Corp.	No	< 11	No	No
UGI Utilities Inc.	No	N.A.	No	Yes
WGL Holdings Inc.	No	< 11	No	No

N.A—Not available. LDC—Local distribution company. > — Greater than. < — Less than.

A prolonged period of high natural gas prices without timely reimbursement of deferred gas cost balances will rapidly deplete an LDC's liquidity. Given today's high and volatile natural gas prices, maintaining strong credit quality necessitates that ratepayers bear the responsibility for commodity costs. Automatic pass-through mechanisms linked to gas price indices provide the strongest level of support because they largely remove regulatory risk from the picture. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels. New Jersey LDCs, for instance, can adjust rates up to three times a year without an official rate case. Although this acts as a pressure release valve in high-price environments, it still exposes LDCs to regulatory uncertainty when the price of gas rises above a preset level. In such circumstances, history provides Standard & Poor's with its best guide to regulators' willingness to accommodate LDCs in their jurisdiction.

Due to the extreme volatility and significant increase in gas prices over the past few heating seasons, more state regulators have revised the timing of their gas adjustment clauses by providing monthly gas adjustment clauses rather than the seasonal end of the heating season adjustment. This expedited treatment helps LDCs to reduce any regulatory lag to recover costs and streamline working capital needs, which in turn should allow LDCs to modestly temper rising gas bills to their customers. In today's new cost paradigm, how quickly the purchased-gas adjustment is "trued up" can have a significant bearing on an LDC's credit quality. Slow recovery could impinge on the firm's liquidity as short-term funds are consumed to finance high-cost gas working-capital needs. In turn, this may necessitate a larger bank line that increases borrowing costs or increased debt levels to term out the short-term borrowings with medium-term notes, potentially increasing pressure on a company's financial profile.

However, some companies like Piedmont Natural Gas Co. Inc. (A/Stable/—) have actually begun the new year by requesting the North Carolina Utilities Commission to reduce the wholesale benchmark to calculate its retail rates from an approved $13 per thousand cubic feet (mcf) in December 2005 to $11 per mcf in January, and make the change effective as of Jan. 1, 2006. This unprecedented request is primarily due to the recent decline in gas prices from peak highs in December 2005 of $15.78 per million Btu to about $7.20 per million Btu today. This represents an example of a working relationship between regulators and LDCs to contain high gas costs and customers' bills.

Weather protection

An LDC's ability to collect a consistent cash stream, regardless of a service territory's weather conditions, provides an important level of stability. Several warmer-than-normal winters or cooler-than-normal summers could significantly change an LDC's financial health unless regulators provide normalization measures. Such protection can be achieved via a normalization clause or rate design. Some jurisdictions such as New Jersey recognize the potential implications of adverse temperatures on unprotected LDCs and provide support accordingly. Other jurisdictions are not as accommodating. SEMCO Energy Inc. and Southwest Gas Corp. have seen their financial profiles weaken partially in response to significant adverse weather conditions.

The growing popularity of weather derivatives serves as an additional avenue for LDCs to pursue weather protection. Regulators that recognize these products as a way to reduce risk for LDCs and their ratepayers tend to allow for derivative cost pass-throughs and do not question the prudence of the strategy.

Earnings sharing

Mechanisms that mandate earnings sharing between shareholders and ratepayers compensate well run LDCs with a share of the profits when companies earn more than their allowed ROE. This gives management an incentive to make their companies' operations more efficient. Sharing also provides downside protection to shareholders and partially shields LDCs during troubled times by, in effect, requiring ratepayers to foot the bill for a portion of lost earnings. AGL Resources Inc., Cascade Natural Gas Corp., Northwest Natural Gas Co., and Southern Union Co. all benefit from earnings sharing in at least a portion of their respective service territories.

Allowed ROE

Like all other for-profit businesses, earning a healthy ROE helps drive success. Fairly set ROEs provide LDCs with capital for system maintenance, growth projects, and capital structure improvement.

Other regulatory mechanisms

Both regulators and LDCs are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and LDCs are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting an LDC's bottom line and still allow companies to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Northwest Natural has a very constructive relationship with the Oregon Public Utility Commission (OPUC) that has resulted in favorable rate design and incentive programs. Northwest Natural is one of the few LDCs that operates under a conservation tariff that insulates its margins from a decline in gas usage levels. Northwest Natural also has a purchased-gas adjustment tariff under which 67% of any difference between actual gas costs and estimated costs (incorporated into rates) will be deferred and charged to customers in subsequent periods, providing protection against commodity price volatility. Finally, Northwest Natural also operates under a weather-normalization tariff that neutralizes 80% of the impact of varying weather patterns on a monthly basis without any dead bands. Oregon regulation also provides for a future test year for ratemaking purposes, thereby minimizing the potential for regulatory lag. All these measures provide for highly stable revenues and margins and contribute to Northwest Natural's solid and very low risk business profile of '1'.

Financial protection from affiliates

Earning a good return provides little benefit if the corporate entity squanders the proceeds. An LDC's credit quality suffers when parent or affiliate companies extract cash proceeds and invest in higher-risk businesses without producing commensurate returns. Regulatory restrictions preventing such dividend flow or mandating minimum equity layers buffer LDCs from more aggressive management teams. Northwest Natural benefits from strong regulatory oversight in Oregon that serves as a template for protecting an LDC's financial interests. In Missouri, regulators have restricted Southern Union from further investment in Panhandle Eastern Pipe Line LLC subsequent to its significant acquisition of the pipeline from CMS Energy Corp. WGL Holdings Inc.'s LDC must gain prior approval from Virginia's regulators to provide intercompany loans to its parent or affiliates, thus contributing to its credit strength. These protective measures provide an added degree of comfort for bondholders.

Markets And Competition

Table 3

Markets and Competition Comparison

Company	Service territory growth (%)	Service territory saturation (%)	Customer mix* (%)
AGL Resources Inc.	1.5 to 2.5	N.A.	80 to 90
Cascade Natural Gas Corp.	> 2.5	< 60	< 80
New Jersey Natural Gas Co.	> 2.5	> 90	80 to 90
Nicor Inc.	1.5 to 2.0	> 90	< 80
Northwest Natural Gas Co.	> 2.5	< 60	80 to 90
ONEOK Inc.	< 1.5	> 90	> 90
People's Energy Corp.	> 2.5	< 60	80 to 90
Piedmont Natural Gas Co. Inc.	> 2.5	< 60	80 to 90
SEMCO Energy Inc.	1.5 to 2.0	60 to 90	< 80
South Jersey Gas Co.	> 2.5	60 to 90	80 to 90
Southern Union Co.	< 1.5	< 60	80 to 90
Southwest Gas Corp.	> 2.5	< 60	80 to 90
UGI Utilities Inc.	> 2.5	60 to 90	< 80
WGL Holdings Inc.	> 2.5	< 60	80 to 90

*Customer mix defined as residential and commercial margins as % of total gross margins. > — Greater than. < — Less than.

Service territory growth

High growth within a service territory due to population influx and new construction could lead to an LDC's greater profitability or rate stability. However, as evidenced by Southwest Gas' struggles, high growth sometimes cuts both ways. Arizona and Nevada benefit from rapid population growth, but the slow pace of regulatory rate adjustments acts as a drag on Southwest Gas' financial ratios because revenues fail to adequately compensate the LDC for its growth capital expenditures on a timely basis. Slower growth in Illinois, on the other hand, provides limited upside for companies, such as Nicor Gas Co. and Peoples Energy Corp., but alleviates the associated regulatory dependence faced by Southwest Gas.

Service territory saturation

Customer saturation refers to the proportion of customers in a given area that use their LDC's services. LDCs that operate in service territories with low growth potential still can grow at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to LDCs operating in low population growth service areas. Northwest Natural benefits from its sub-50% saturation rate and good service territory growth, while Peoples Energy faces a disadvantageous combination of a relatively high saturation rate and low service territory growth.

Customer mix

An LDC serving a large proportion of industrial or wholesale customers faces greater instability than an LDC serving only residential customers. Nicor and Peoples Energy, for instance, serve a broad customer base consisting of many small retail users, as opposed to a few large industrial users, which reduces dependence on individual customers. LDCs that depend on the sustainability of a few key industrial users carry not only gas distribution risk, but also business risk associated with the large customers. Furthermore, large users often have greater financial incentive to switch to alternative fuel sources because of extreme input cost sensitivity in certain energy-intensive industries.

Protection against bypass

Due to their proximity to interstate gas pipelines, some large customers have the ability to directly tie into a transmission line and completely bypass LDCs' services. Although such pipelines provide key sources of gas supply for LDCs, it is important to recognize this bypass risk. Ideally located LDCs have adequate transmission access but have industrial customers far from interstate pipelines.

Wealth demographics

A wealthy customer base reduces the risk of customer nonpayment and often translates into less resistance to distribution rate increases. Furthermore, wealthy customers are less sensitive to their marginal gas consumption, which can lead to higher usage. Suburban areas of New Jersey—outside of New York City and Philadelphia—offer examples of high-wealth customer concentrations that benefit the regional LDCs.

Operations

Supply position

Drawing from a single interstate pipeline or relying on a particular gas basin exposes LDCs to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects LDCs from such disruptions. With its strategic location in Chicago, Ill., Peoples Energy has an ideal supply position. The company has direct interconnections to six major pipelines (Natural Gas Pipeline Co. of America, ANR Pipeline Co., Trunkline Gas Co., Midwestern Gas Transmission Co., Northern Border Pipeline Co., and Alliance Pipeline L.P.) and can draw gas from the Midcontinent, Gulf Coast, and Canada. The numerous pipeline connections allow the company to negotiate gas purchases and storage arrangements at competitive prices.

Storage position

Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities for LDCs without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. LDCs benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Northwest Natural can meet more than 60% of peak demand with company-owned storage, leased storage, and recall agreements. Such storage has lowered the company's average commodity costs and allowed it to meet peak demand without having to pay for additional transportation costs.

System condition

Outdated systems requiring extensive maintenance and capital expenditures lower LDCs' profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, LDCs generate operational efficiencies through the use of new technology. Technology allows Southwest Gas field employees to receive work orders without driving to the office in the morning and read meters without leaving their vehicles. Although often involving material upfront costs, such technological improvements provide significant long-term savings.

Hedging

LDCs can hedge against gas price volatility by using financial instruments and locking in long-term purchase contracts with its suppliers. The hedging of fixed-price purchases reduces exposure to physical market price volatility, preserves the value of storage inventories, and provides risk-management services to a variety of customers. Those companies that have locked in prices through long-term contracts, financial instruments, or both that are below the high average prices over the past three heating seasons have reduced their exposure to high gas prices. Many LDCs' hedging programs need to be preapproved by regulators. We view prudent, consistent hedging programs that have been preapproved by regulators as a credit strength. For example, Piedmont Natural Gas provides a hedging program, which requires preapproval by its regulators.

Management

As in all business segments, ownership structure, management practices, internal controls, corporate governance, and financial disclosure policies fall under the management umbrella and are all regularly examined as part of our ratings methodology for LDCs.

Within the ownership structure analysis, links to parent companies or affiliates are important considerations. Ownership by stronger or weaker parents substantially affects the rated entity's credit quality. The nature of the owner—holding company or strategically linked business—can also hold significant implications for business and financial aspects of the rated entity. Standard & Poor's deems many LDCs to have the same creditworthiness as other entities within their corporate structure because of strategic linkages and the free flow of funds among the entities.

Assessment of management personnel and practices is an especially significant determinant of a rating. Standard & Poor's analysis considers many factors that pertain to management, including track record and competence, management background and reputation, and management depth and turnover. Business strategies that stray from core competencies, initiatives that bear elevated risk, and actions inconsistent with public or private statements detract from credit quality. We place a higher degree of confidence in management teams that possess significant industry experience, consistently meet or exceed forecast projections, and deal openly with pressing credit issues.

Financial disclosure and management oversight help round out the broader area of governance. Does an impartial board of directors help monitor critical decisions? Are all potential conflicts of interest disclosed in a timely manner? Are all SEC filings on time? The answers to these questions help provide intangibles to the rating process.

Rating Actions

There have been several adverse rating actions in the LDC universe over the past three to four heating seasons (36-40 months) for a variety of reasons, with 10 outlook revisions to negative, five CreditWatch placements with negative implications, and five downgrades. During 2005, there were two outlook revisions (one to negative from stable and one to stable from positive), one CreditWatch placement with negative implications, and one downgrade compared with only one upgrade that occurred in early January 2005. Thus far in 2006, there has been two rating actions, with a negative outlook revision from stable and a CreditWatch placement with negative implications, due to a combination of increased regulatory uncertainty and increased exposure to nonregulated activities.

These adverse rating actions have been due to some combination of the following:

- Sustained high leverage and weaker-than-expected credit protection measures,
- Increased exposure to, or investment in, nonregulated businesses,
- Increased debt-financed acquisitions or capital investments, and
- Weak regulatory mechanisms and support.

Conversely, the favorable rating actions during the past three heating seasons, which have been more modest, have consisted of three upgrades, one outlook revision to positive (which recently was revised back to stable in 2005), and two rating affirmations with an outlook revision to stable from negative. These positive rating actions have been attributable to:

- Increasing customer growth and improving cash flow and financial profile, while maintaining sound liquidity,
- Prudent financings by using a combination of debt and equity as well as the successful integration of acquisitions in certain cases, and
- Demonstrated strength of regulatory support and rate mechanisms during challenging, high natural gas price heating seasons.

The outlook for the LDC universe continues to have some negative pressures with eight out of the 14 rated LDCs possessing a negative outlook or CreditWatch with negative implications, and no company with a positive outlook. The remaining six LDCs have a stable outlook (two of which were recently downgraded in 2005). In general, the majority of the LDCs possess 'A' ratings, a stable outlook, or both which represent our general view of LDCs' cash-flow stability and low business risk profiles.

Nevertheless, current high gas prices will remain a challenge for all LDCs and may further pressure ratings for those LDCs that have a negative outlook and whose financial measures are somewhat stretched for their current ratings. In addition, management's financial policy and commitment to credit quality will also play an integral role in a company's ability to manage and sustain its credit quality during a fourth consecutive heating season with a higher-than-average natural gas pricing environment.

Table 4

Financial Profile Comparison*

Company	FFO interest coverage (x)	FFO to total debt (%)	Net cash flow/capital expenditures (%)	Discretionary cash flow (mil. $)	Average return on capital 2002-2004 (%)	Total debt to total capital (%)
AGL Resources Inc.	5.0	18.4	86.7	(52.0)	10.5	59.2
Cascade Natural Gas Corp.	4.3	24.5	79.9	(18.3)	9.6	59.8
New Jersey Natural Gas Co.	7.0	19.1	87.3	(157.9)	12.4	56.6
Nicor Inc.	6.6	26.1	96.4	45.3	9.7	58.3
Northwest Natural Gas Co.	4.2	20.0	51.9	67.2	8.8	51.4
ONEOK Inc.	4.8	19.8	169.5	(148.5)	10.5	63.8
People's Energy Corp.	4.9	20.6	63.3	(66.6)	8.8	52.9
Piedmont Natural Gas Co. Inc.	3.8	16.4	58.1	(50.7)	10.9	47.8
SEMCO Energy Inc.	1.8	6.7	101.6	6.0	7.1	71.8
South Jersey Gas Co.	5.3	20.9	89.6	(15.3)	9.8	55.2
Southern Union Co.	3.4	12.3	96.0	(28.6)	2.9	55.0
Southwest Gas Corp.	3.6	18.0	70.3	(180.0)	7.1	66.8
UGI Utilities Inc.	3.5	21.4	204.8	67.8	13.0	65.6
WGL Holdings Inc.	5.5	26.4	131.4	66.4	10.0	46.8

*Financials as of fiscal year-end 2004. FFO—Funds from operations.

We expect many of these companies listed in the table above to either maintain or continue to gradually improve their financial profiles. Still, the outlook for six LDCs is negative. The negative outlook for Southern Union, Nicor Inc., and AGL primarily reflects their increased financial leverage and weakened credit protection measures and their respective near-term challenges to significantly improve their financial profiles. In addition, AGL's and UGI Utilities Inc.'s negative outlooks are also related to their increased exposure to nonregulated operations (i.e., energy marketing and propane business) increasing their business risk profiles and need to generate stronger financial measures commensurate with their respective ratings. Finally, the negative outlook on WGL reflects its absence of weather normalization and increased exposure to its retail energy marketing business, which could further reduce the company's current liquidity cushion.

Cascade Natural Gas has a positive outlook tied to its improving financial profile based on solid customer growth, a reliable purchased-gas adjustment mechanism that ensures full recovery of gas supply costs, and a manageable capital spending program that should allow the company to continue to meet its debt reduction plans in 2006.

The Credit Challenges Ahead

Regulators will always have to balance timely and prudent gas cost recovery with ratepayer resistance to rising gas bills. Continued regulatory support is paramount to credit quality for LDCs, especially during periods of prolonged high natural gas prices and the likely need for LDCs to fund working capital needs with additional debt. LDCs will remain challenged in this elevated gas price environment to reduce short-term debt balances and avoid creeping debt leverage, which could trigger deterioration in credit quality.

Peoples energy is an example of how an uncertain and challenging regulatory environment can put pressure on a company's credit quality. In February 2006, Standard & Poor's revised the outlook on Peoples Energy to negative from stable due to the challenging regulatory climate in Illinois, which has become highly politicized as the historically supportive gas distribution regulation has become more contentious. In addition, the outlook revision also incorporated the company's continued increased investment in nonregulated diversified businesses, which include oil and gas production, power generation, midstream services, and retail energy services.

In the end, a company's business risk profile must be analyzed in conjunction with its financial risk profile (see table 4). Because investors in the LDC universe rely on stable cash flow, strong financial metrics may simply overpower chinks in the business profile armor. Nicor's stratospheric cash flow ratios drive the company's 'AA' rating despite average regulatory, market, and competition characteristics. Good financial metrics at New Jersey Natural Gas also support that company's strong rating.

More recently, Standard & Poor's has further scrutinized the financial profiles and overall liquidity for companies that have increased their exposure to nonregulated energy trading activities. For example, AGL's credit quality is tempered by the heavy liquidity requirements of its nonregulated businesses (primarily through its subsidiary Sequent, a gas marketing and trading company) and the company's growth strategy that could potentially increase its exposure to unregulated activities (see table 5).

Table 5

Diversified Activities Comparison

Company	***Diversified activities as % of consolidated entity***	***Main areas of focus***
AGL Resources Inc.	20	Wholesale and retail services
Cascade Natural Gas Corp.	Less than 5	Retail gas marketing to a small number of large customers
New Jersey Natural Gas Co.	22	Natural gas utility, energy marketing, and pipeline capacity management
Nicor Inc.	10	Shipping
Northwest Natural Gas Co.	9	Interstate gas storage
ONEOK Inc.	70	Gas gathering and processing; energy marketing and trading
Peoples Energy Corp.	10	Gas distribution
Piedmont Natural Gas Co. Inc.	10	Pipelines and retail gas marketing
SEMCO Energy Inc.	90	Propane and retail energy services
South Jersey Gas Co.	30	Natural gas utility, energy marketing, and marina energy (Borgata project in Atlantic City, N.J.)

Table 5

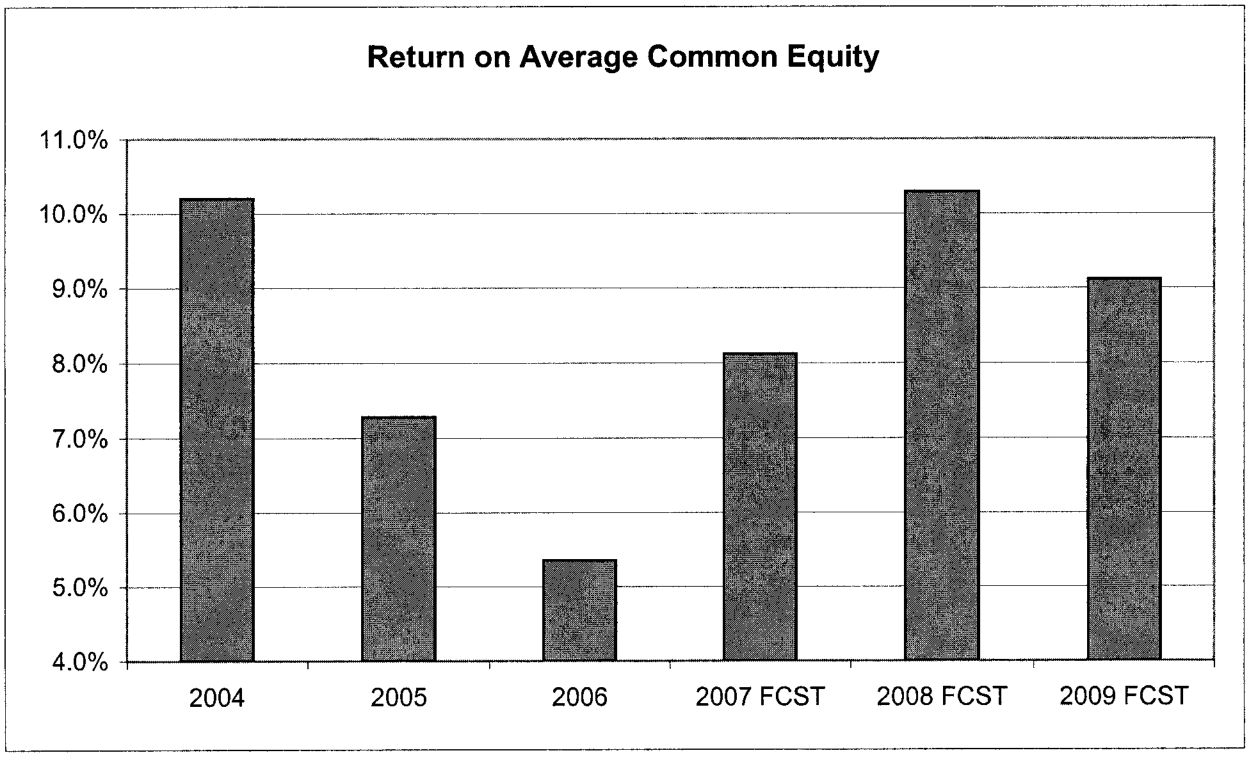
Diversified Activities Comparison

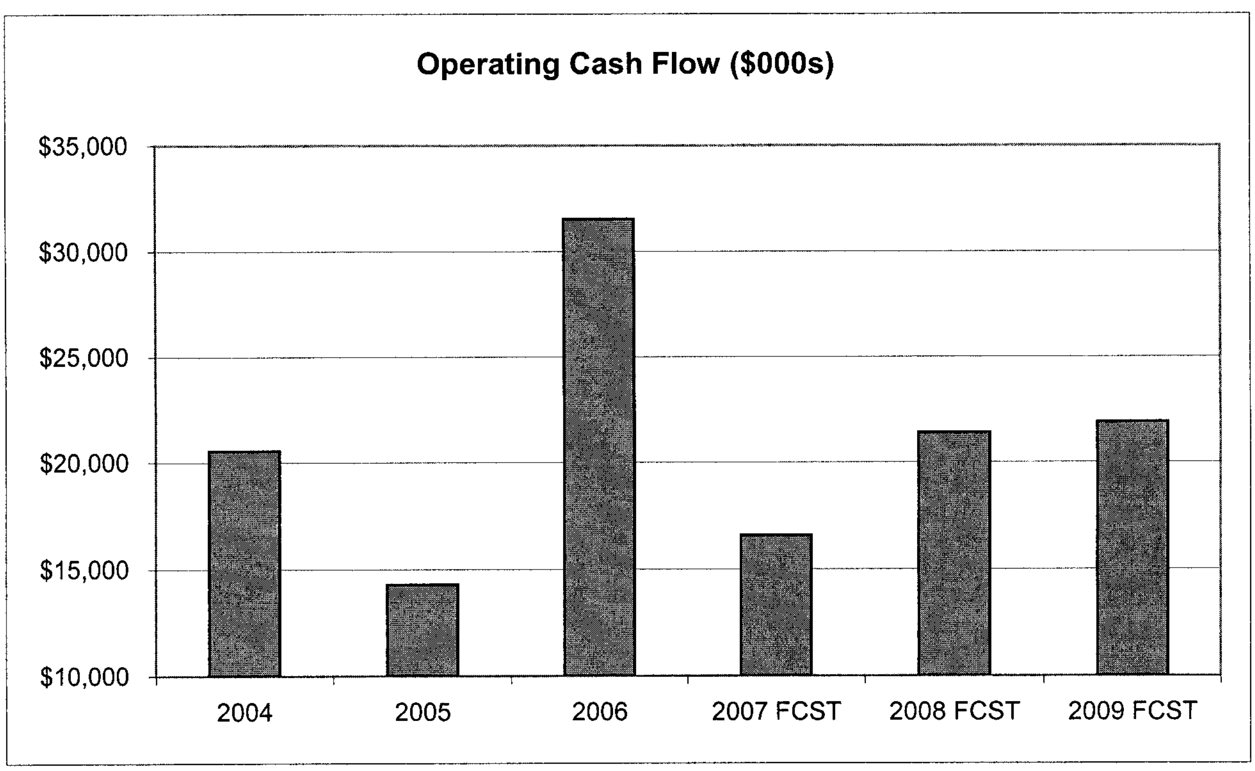
Company	Diversified activities as % of consolidated entity	Main areas of focus
Southern Union Co.	88	Natural gas pipelines; gas gathering and processing
Southwest Gas Corp.	Less than 10	Construction
UGI Utilities Inc.	50	Propane and retail energy services
WGL Holdings Inc.	2	Retail gas

EXHIBIT

KCG-13

UNS Gas, Inc.
Updated Financial Forecast with Company's Proposed Rates
Summary of Key Financial Indicators





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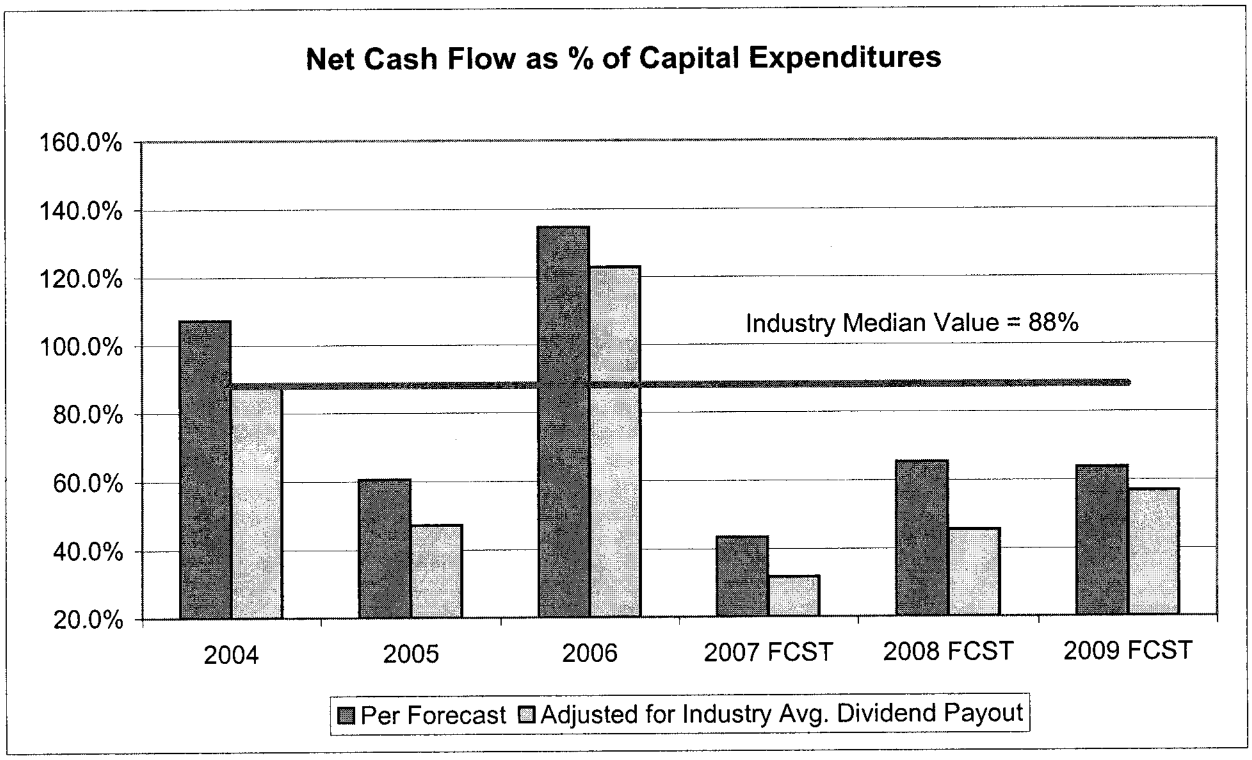

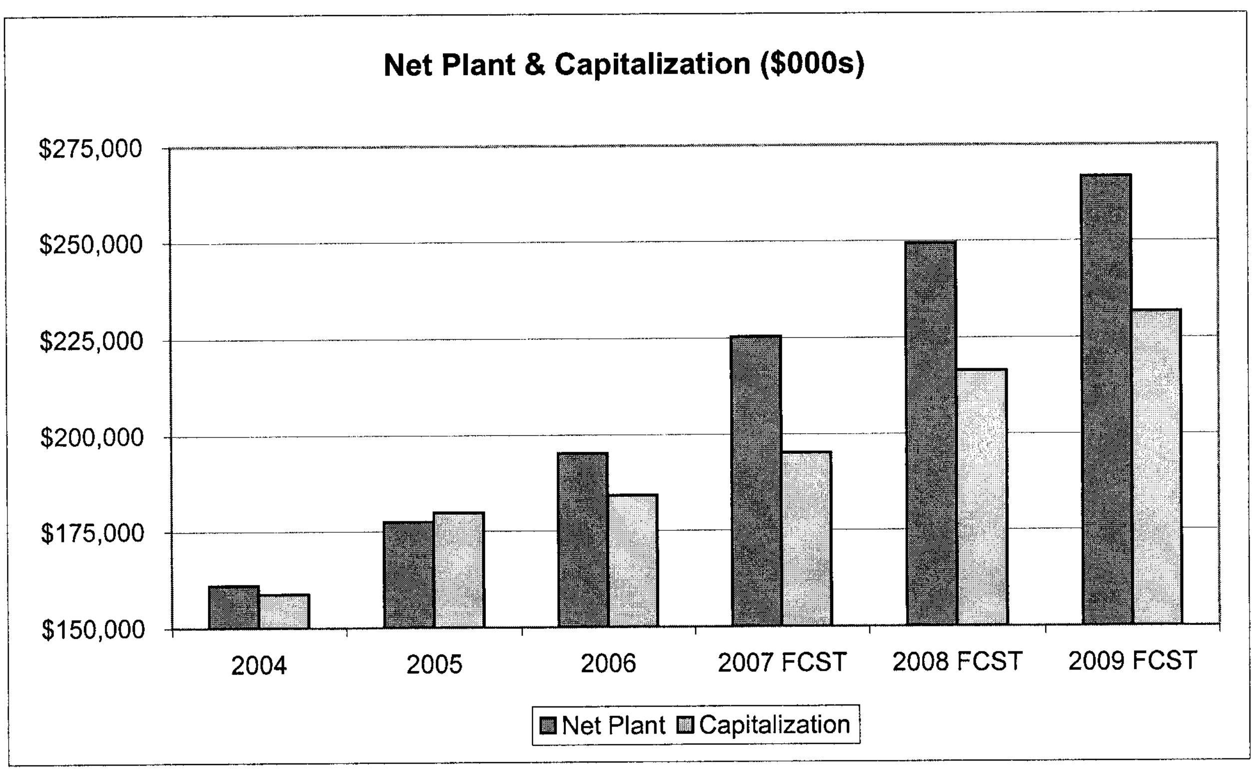

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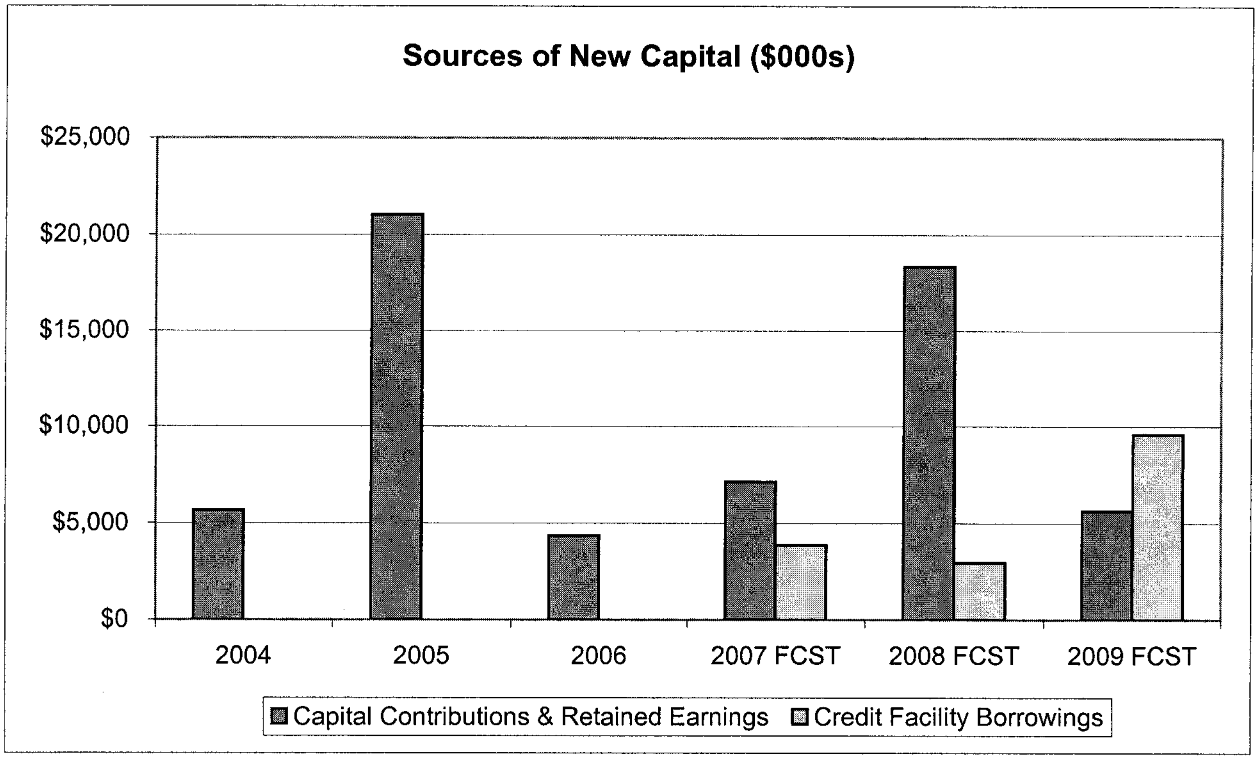

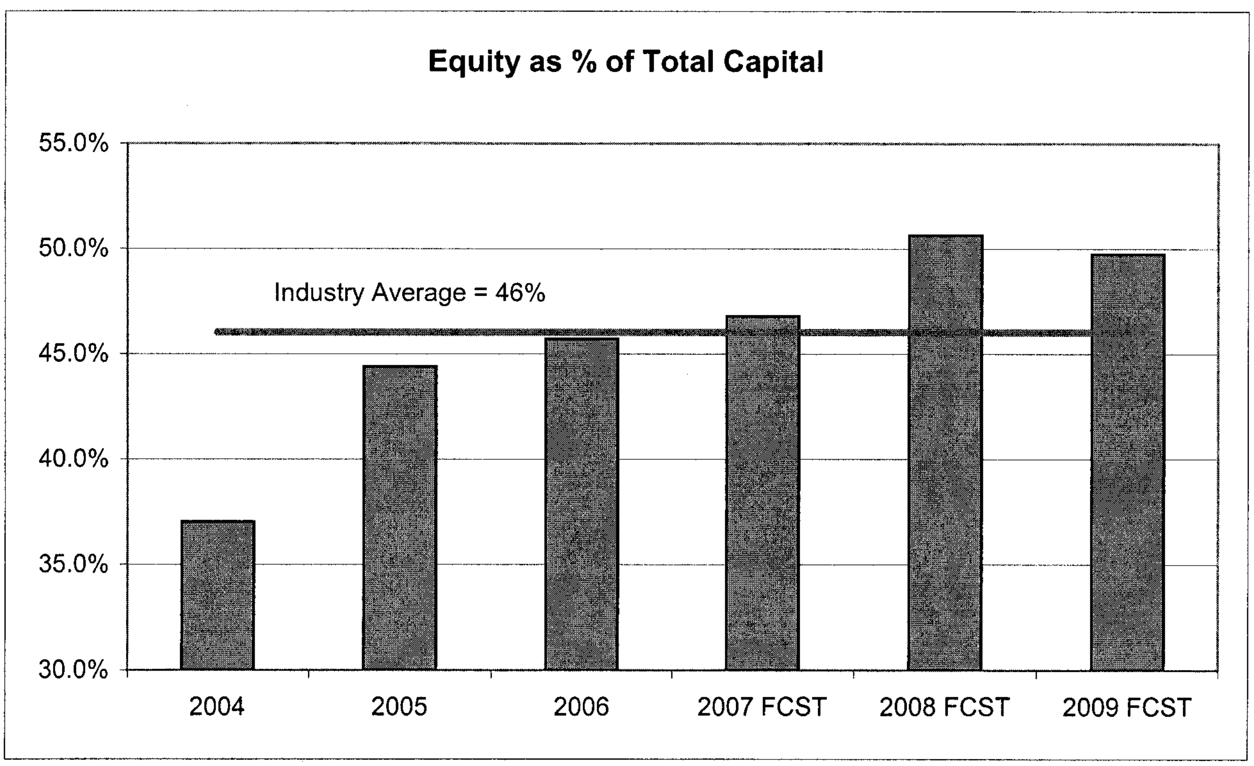

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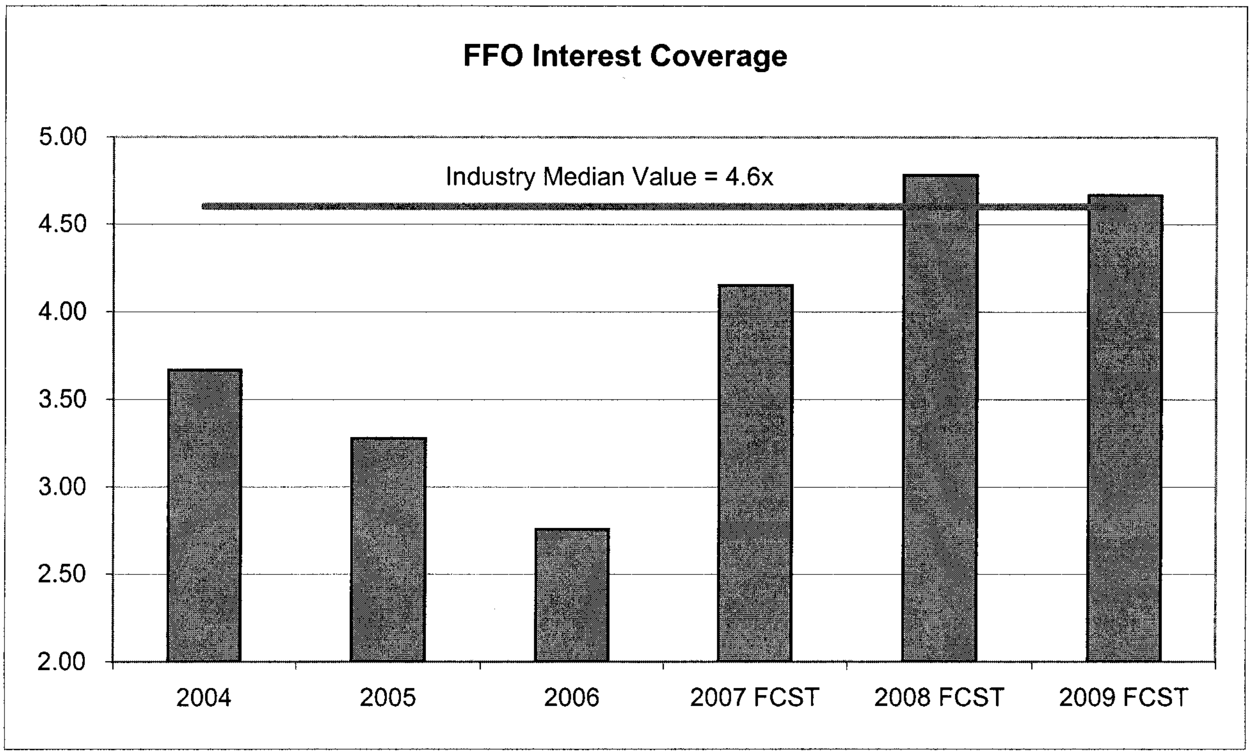
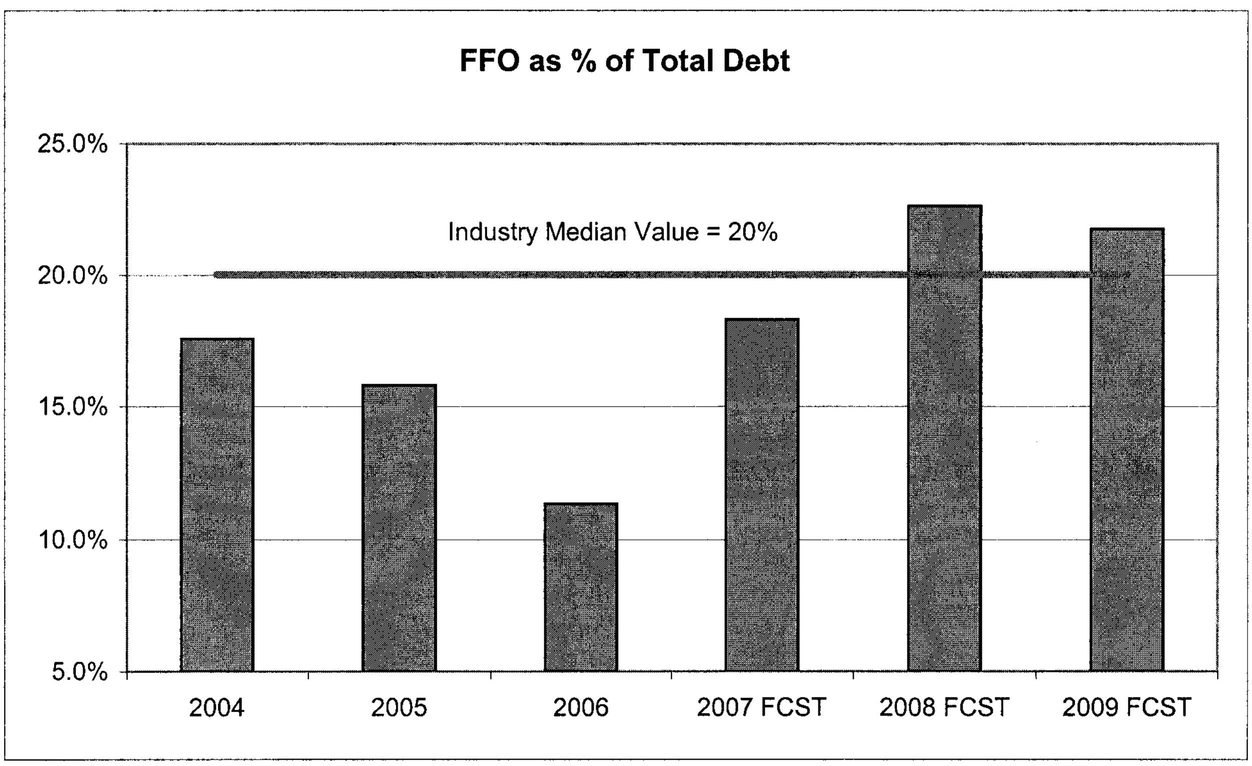
Summary of Key Financial Indicators

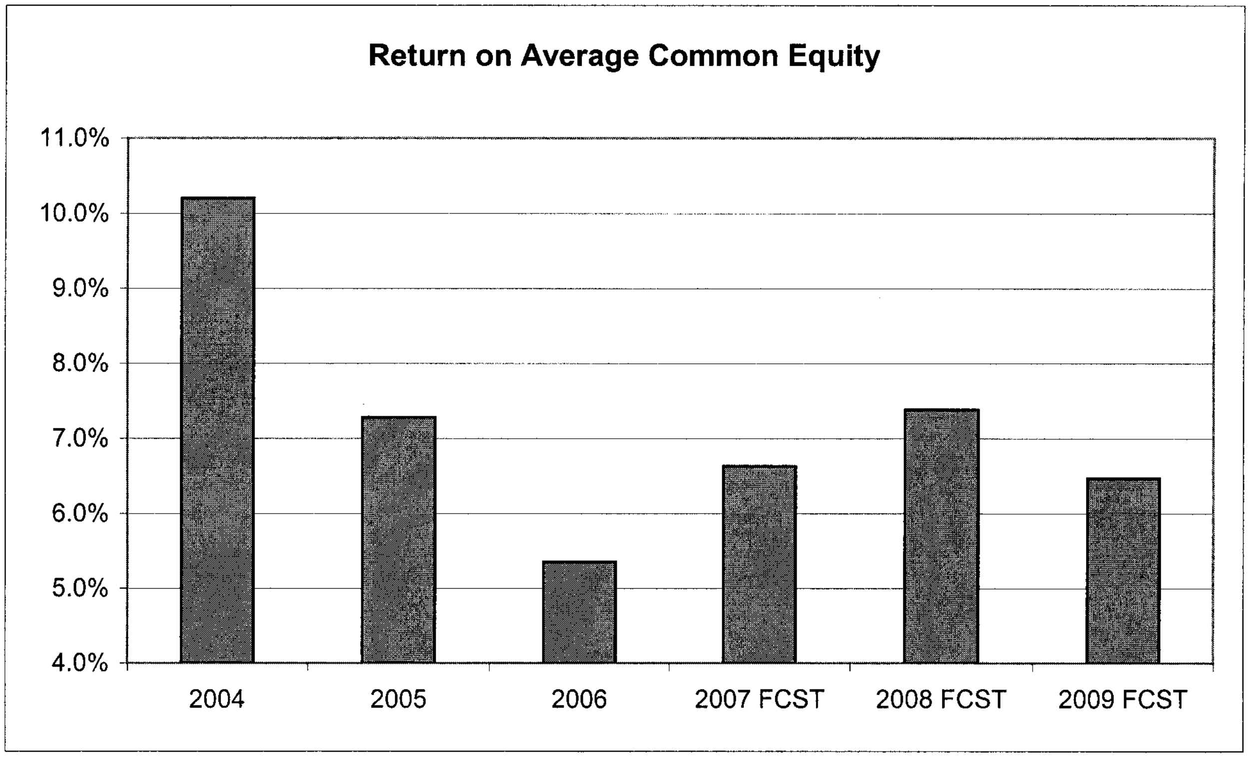


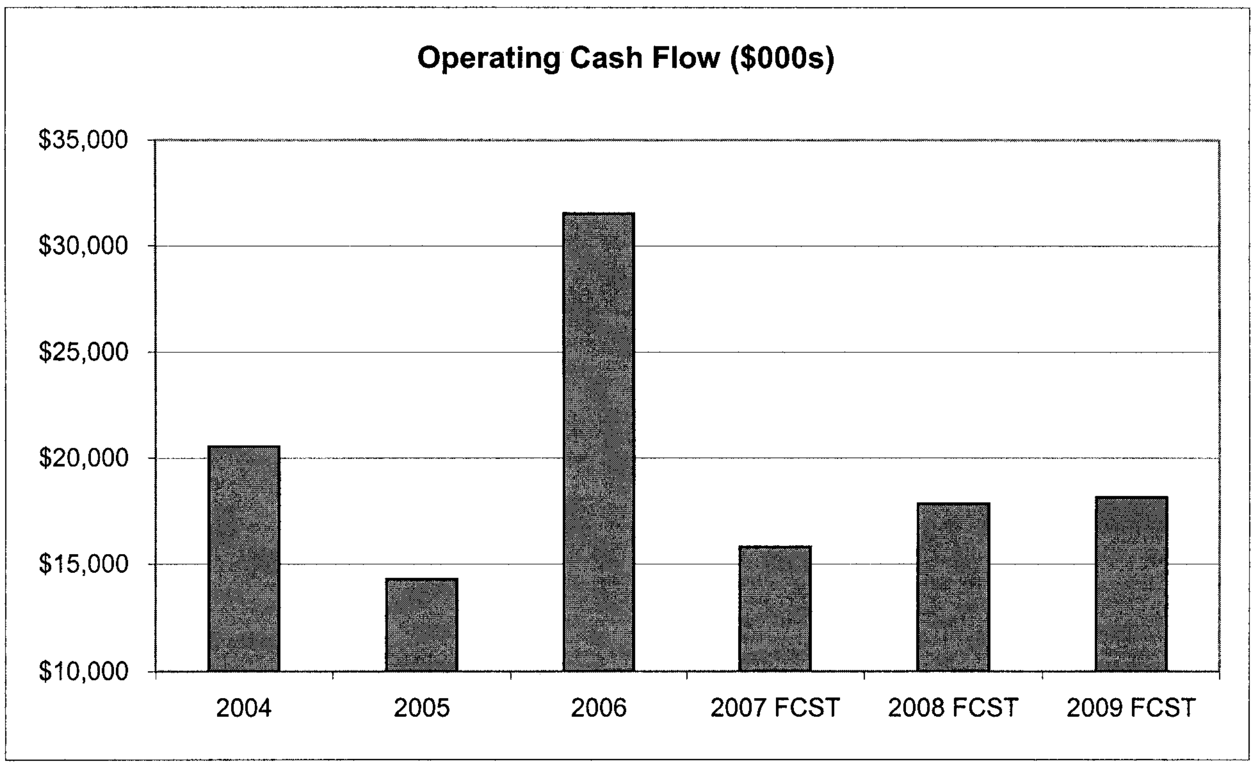


EXHIBIT

KCG-14

UNS Gas, Inc.
Updated Financial Forecast with Staff's Proposed Rates
Summary of Key Financial Indicators





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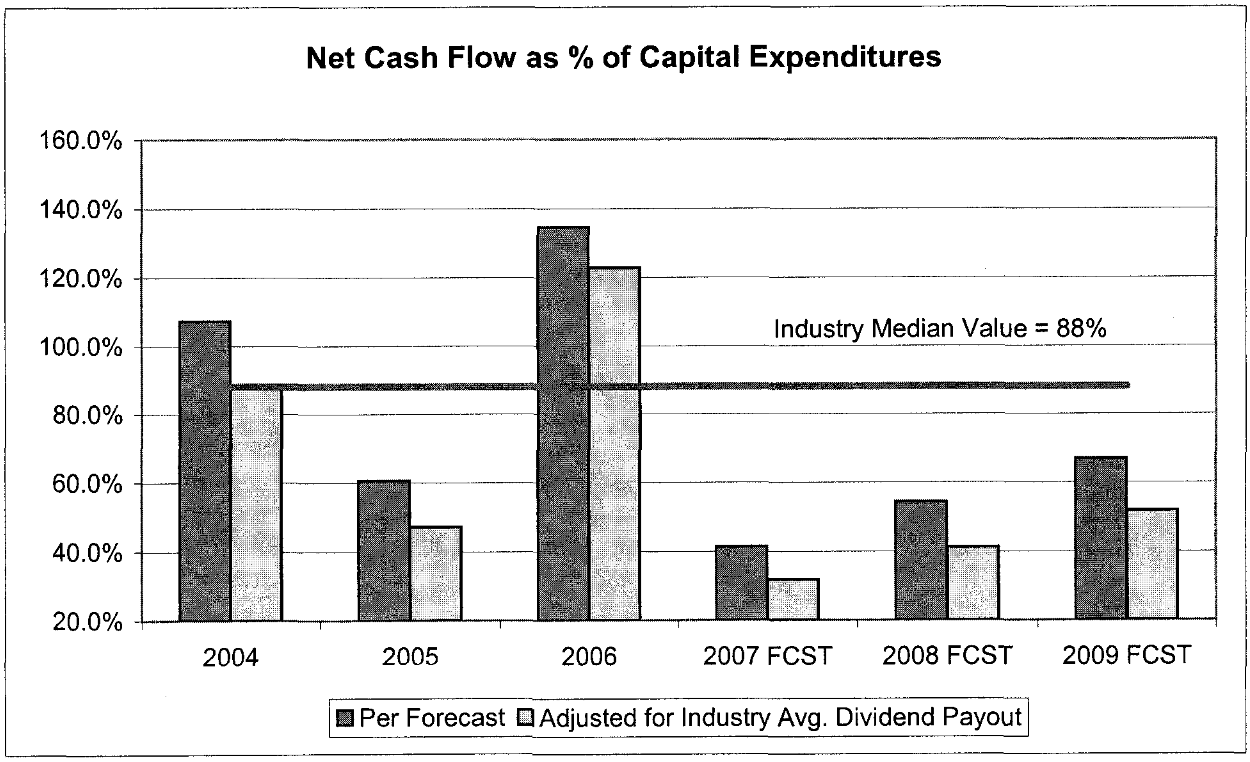

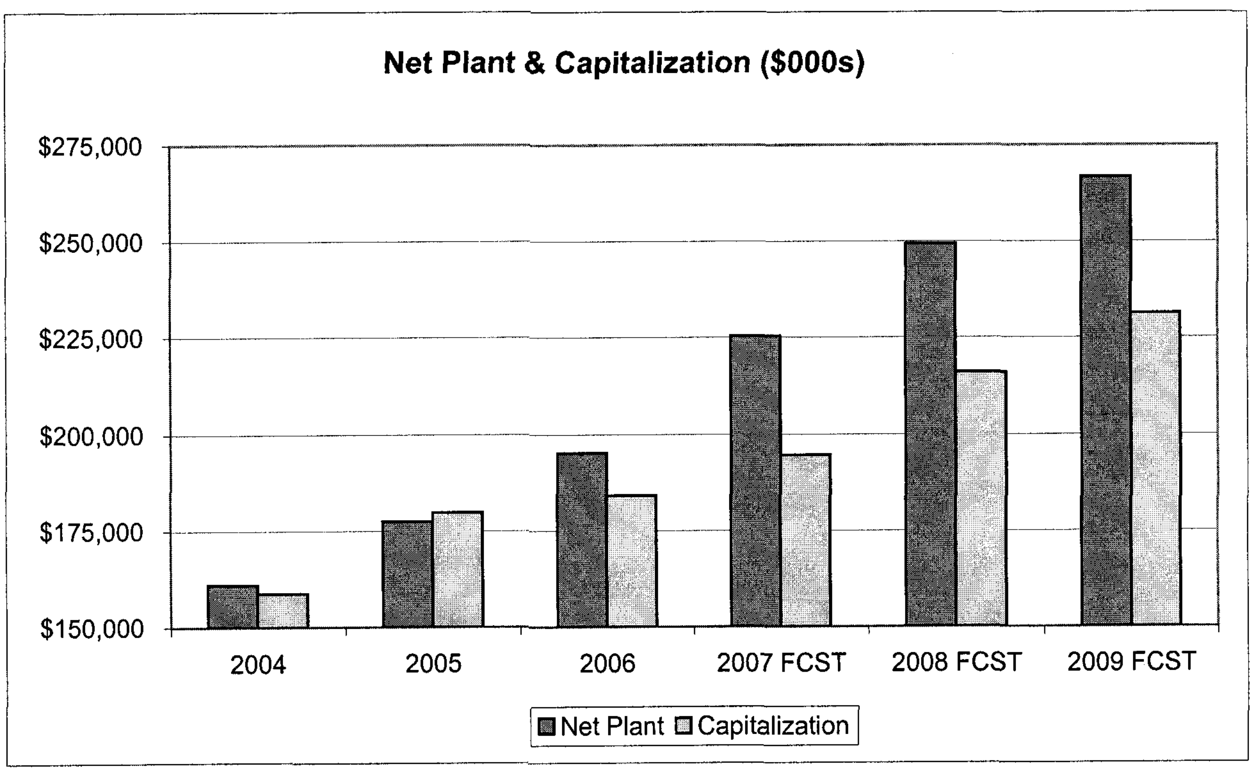

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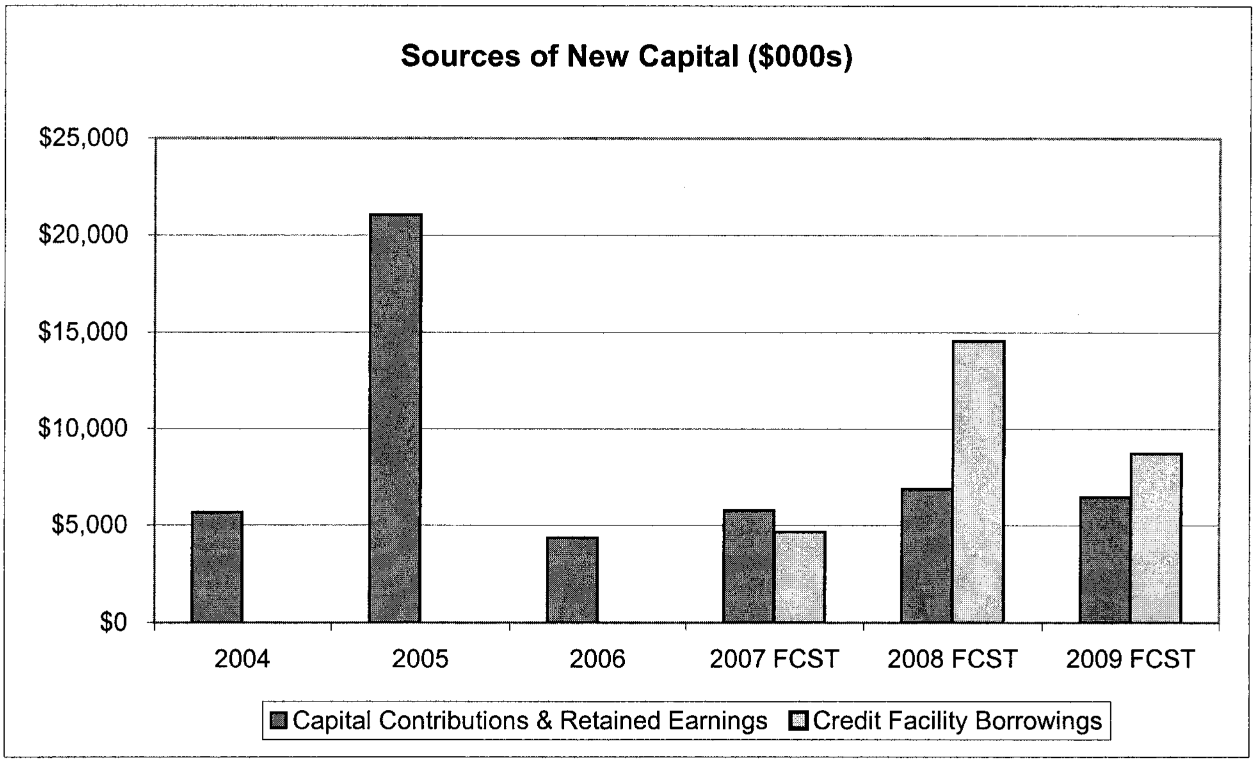

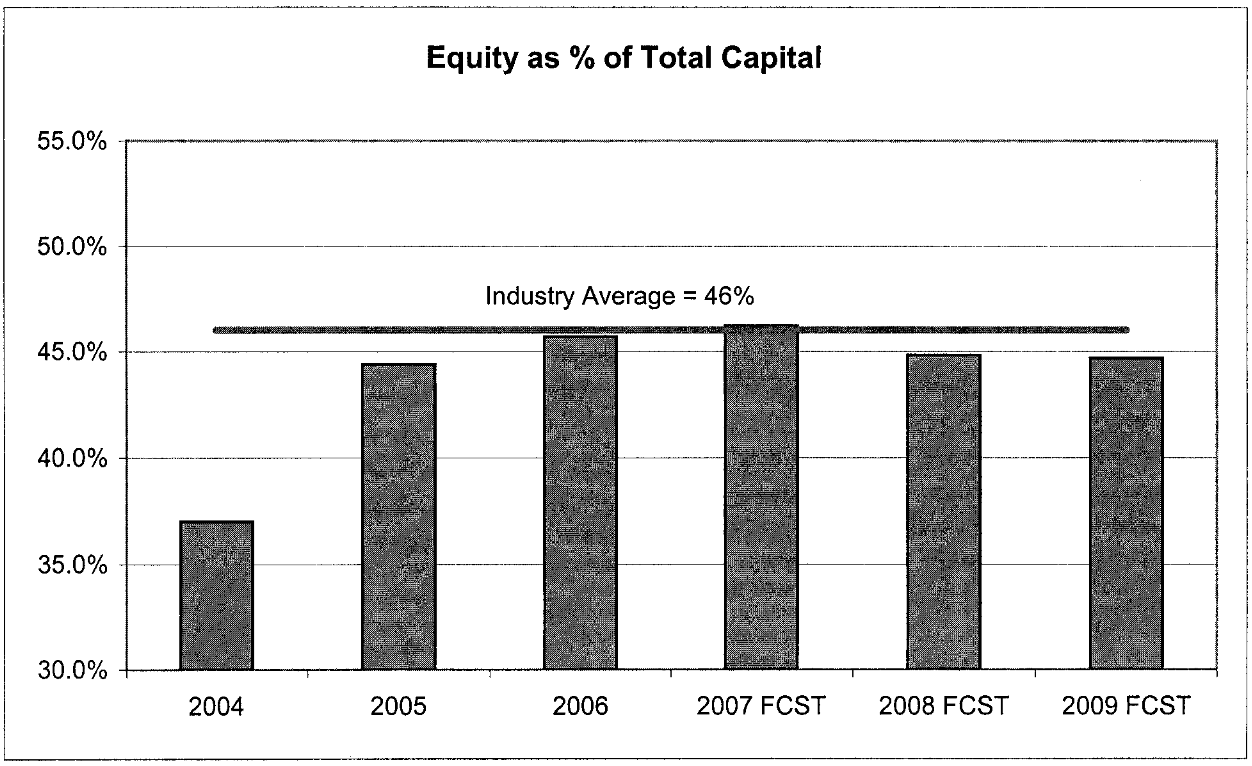

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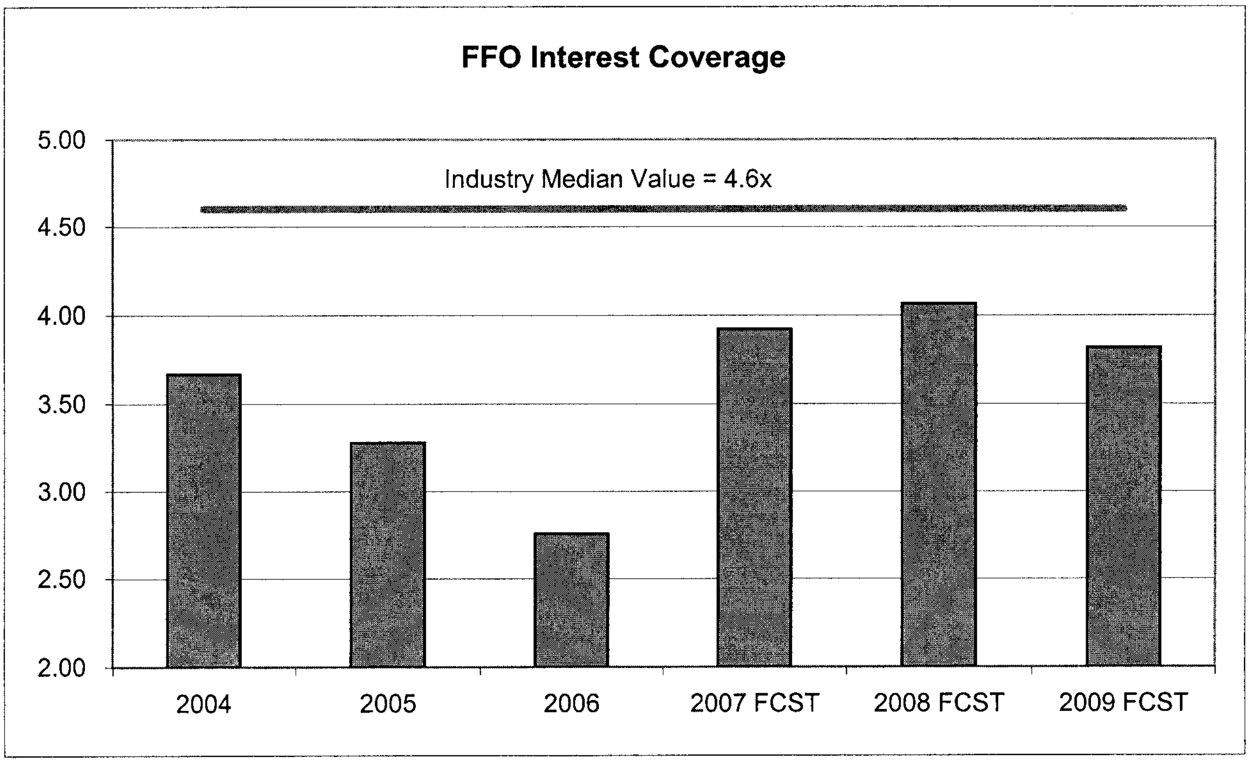

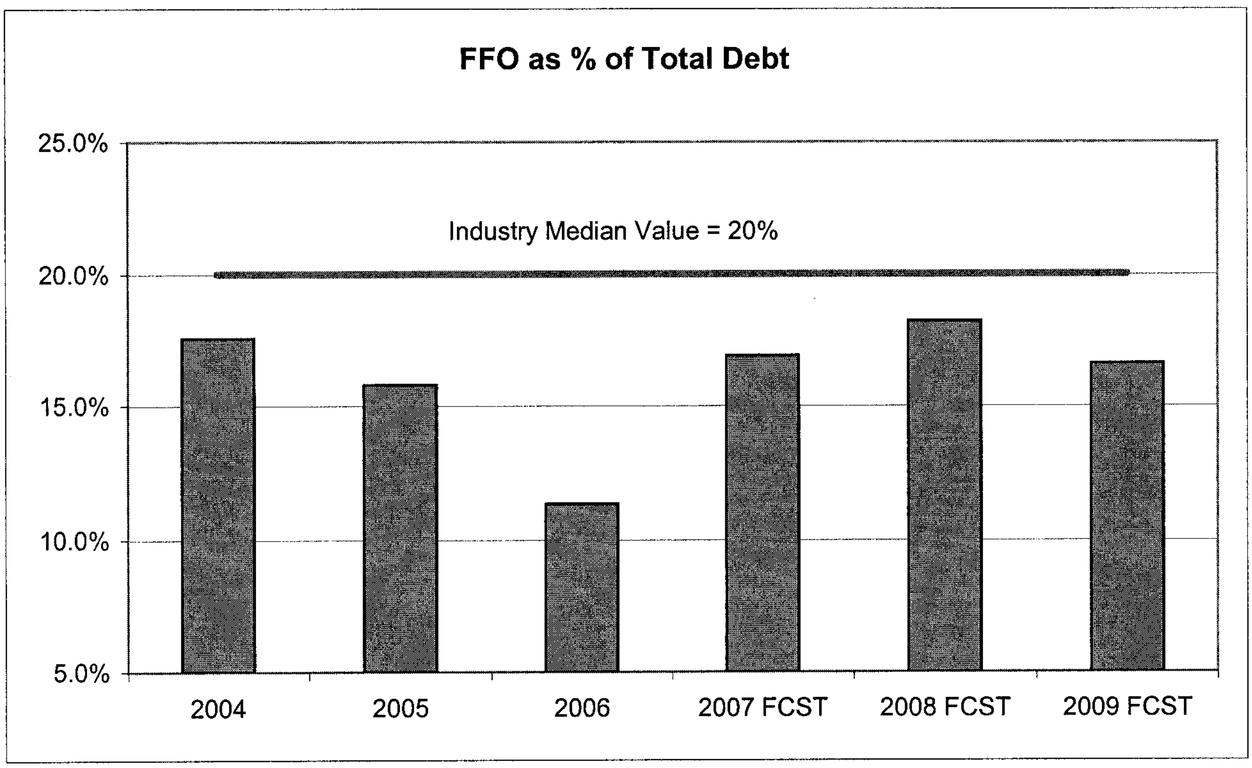

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

Dallas J. Dukes

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is One South Church Avenue, Tucson, Arizona 85702

Q. Are you the same Dallas J. Dukes that filed file Direct Testimony is this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Which Commission Staff and/or Intervenor Direct Testimonies will you be addressing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I address adjustments that Staff Witness Ralph C. Smith recommends in his Direct Testimony. I also address several adjustments that Residential Utility Consumer Office ("RUCO") witnesses Marylee Diaz Cortez and Rodney L. Moore propose in their Direct Testimonies. While I agree with some of the adjustments made, the majority of adjustments Staff and RUCO make are inappropriate and should not be accepted. Further, I provide ample justification for UNS Gas, Inc.'s ("UNS Gas" or the "Company") proposals on these items in my Rebuttal Testimony in order to rebut these Staff and RUCO adjustments. In short, I believe the adoption of many of Staff's and RUCO's adjustments is not supportable based on all of the evidence and documents in this case.

II. <u>REBUTTAL TO STAFF WITNESS RALPH C. SMITH</u>.

Q. Could you please summarize your view of the Direct Testimony filed by Mr. Ralph C. Smith on behalf of Staff?

A. I disagree with several of the adjustments he makes in his Direct Testimony.

A. <u>Bad Debt Expense (Staff Adjustment C-3)</u>.

Q. Mr. Dukes, do you agree with the recommendation of Mr. Smith for Bad Debt Expense?

A. Partially. Mr. Smith has basically used the Company's bad debt expense calculation. The differences are attributable to Mr. Smith using the Staff's revenue adjustments for customer annualization and weather normalization as opposed to the Company's. The Staff's adjustments are being opposed by Company's rebuttal witness, D. Bentley Erdwurm, and for reasons stated in his Rebuttal Testimony the Company's bad debt expense adjustment should be accepted without change.

B. <u>Remove Depreciation & Property Taxes for Construction Work in Progress ("CWIP") (Staff Adjustment C-4)</u>.

Q. Do you agree with Mr. Smith's adjustment to remove the Company's proposed Depreciation and Property Tax adjustment for CWIP included in rate base?

A. No. The adjustment is directly associated with the inclusion of CWIP in rate base as a plant item. Mr. Kentton C. Grant is the Company's witness in support of the inclusion of CWIP in rate base. Because CWIP should be included in rate base for the reasons Mr. Grant explains in his Rebuttal Testimony, the Company's depreciation and property tax adjustment should not be adjusted as Mr. Smith proposes.

Q. If the Commission chooses to exclude CWIP from rate base are there other adjustments to rate base that should be made?

A. Yes. If the Commission disallows the inclusion of the CWIP balance that UNS Gas is requesting within rate base; then the customer advances directly related to projects within that CWIP balance should also be taken out as a reduction to rate base. There is $4,158,264 within the customer advances total that is directly related to projects contained in the CWIP balance as of the end of the test year. It would not be proper to reduce rate base for advances that are directly for plant items that are not included within rate base.

C. Geographic Information System ("GIS") Expenditures (Staff Adjustments B-2 & C-5).

Q. Do you agree with Mr. Smith's recommendation to disallow the Company's request to include GIS expenditures as a regulatory asset and to recover that asset through amortization?

A. No. I do not.

Q. Can you give a quick overview of why the Company is requesting the inclusion of certain GIS expenditures within rate base?

A. Yes. The Company is requesting the recovery of, and on, certain GIS expenditures (made in response to the directive of the Commission) that provide present and future benefits to customers.

In 2002, the Commission's Pipeline Safety Section Staff issued a directive to the Arizona Gas Division of Citizens Communications Company ("Citizens Gas") to complete the mapping of service lines. In August 2003, UniSource Energy Corporation ("UniSource") purchased Citizens Gas assets, which then became part of UNS Gas. The Company initiated a project to locate and map into GPS all of the existing service lines in order to comply with the Commission directive.

Initially, this project was classified as a capital project based on the information submitted to the accounting department at the time the project was being approved. However, in the final quarter of the test year the accounting department became aware of the misclassification and made an adjusting entry to properly classify expenditures as an expense per Generally Accepted Accounting Principles ("GAAP"). In December 2005, a correcting entry was made and $897,000 (pre-tax) of expenditures was expensed that had originally been capitalized. These changes all occurred during UNS Gas' test year in this case.

Q. Why didn't the Company request an Accounting Order to defer the GIS expenditures in question?

A. The appropriate time to request an accounting order would have been in 2003, prior to beginning the project. However, as I stated above, the Company initially believed this was a capital project and thus had no reason to request deferral treatment at that time. The accounting adjustment itself (from capital to expense) was not finalized until December 2005. Thus, the correction was made in the final month of the test year and impacted the operating income of the test year.

Because the impact was within the test year, the Company believes the more appropriate action is to seek the requested treatment within a rate case. Thus, we have requested the Commission allow the Company to back the GIS expenditures out of the test year, record them as a regulatory asset and allow recovery of the expense over the expected life of the rates.

Q. What were the reasons Mr. Smith provided for excluding the GIS expenditures from rate base?

A. Mr. Smith states the following on pages 16 to 17 in his Direct Testimony:

> Based on a review of the Company's October 3, 2005 memo and the supporting documentation provided by UNS Gas, Staff concludes that the deferred GIS costs requested by UNS Gas are not an appropriate rate base item, do not qualify as a "regulatory asset," were not pre-approved for deferral by the Commission, are non-recurring costs that should have largely been expensed by the Company in periods prior to the 2005 test year, and the therefore are not appropriate to include in test year rate base.

Q. Do you agree with Mr. Smith's assertion that the GIS costs are not an appropriate rate base item?

A. No, I do not. Mr. Smith did not question the prudence of the expenditures or the benefits of GIS to customers. It was also pointed out by the Company's witness, Gary A. Smith, that the Company incurred the GIS expenditures in response to a directive from the Commission's Pipeline Safety Section.

Ultimately, the Commission has broad discretion to decide what types of expenditures merit rate base treatment. It is the Company's position that these particular expenditures represent a substantial one-time investment in the initial implementation of a system that provides benefits to its current and future customers. The Company believes that merits the Commission's consideration and ultimate approval of such treatment based on the circumstances as discussed above.

Q. **Do you agree with Mr. Smith's assertion that the GIS costs do not qualify as a regulatory asset?**

A. No, I do not. I first note that these expenditures are used and useful to insuring safe and reliable service to customers and result from directive from the Commission's Pipeline Safety Section. Ultimately the Commission has the discretion to decide that the GIS costs should be classified as a regulatory asset, and I believe they should be so determined because of the GIS costs nexus to directly providing safe and reliable natural gas service to customers.

Q. **Do you agree with Mr. Smith's assertion that because the Company did not request deferral treatment of the cost; they should not be allowed rate base treatment?**

A. No. As I mentioned previously, the Commission has broad discretion to consider the particular circumstances and merit of the Company's request and to grant rate base treatment and recovery if found appropriate. We are requesting the Commission consider:

1. That the project was started in 2003 as a capital investment and a correction of book accounting treatment dictated the expensing of the costs for GAAP purposes in December 2005;
2. The magnitude of the Company's investment relative to its accumulated earnings (7.6% or $897,068/$11,825,983);
3. The benefits provided to present and future customers as a result of the investment made by the Company;
4. That the Company made this significant investment to meet the Commission's directive issued to the predecessor company, Citizens Gas; and
5. That if the Company is not granted recovery of the investment, customers will reap the benefits of a system and the investors will have borne the cost without recovery.

D. Incentive Compensation (Staff Adjustment C-6).

Q. Mr. Dukes, can you briefly summarize Mr. Smith's adjustment to test year Incentive Compensation?

A. Yes. Mr. Smith has suggested an equal sharing of the costs associated with the Company's various employee incentive programs. Mr. Smith's primary reasoning for this sharing is that it strikes the balance between the benefits attained by both shareholders and customers. He also references a recent Commission Decision No. 68487 (February 23, 2006) – the Southwest Gas Corporation ("SWG") rate case – in which the Commission adopted such a recommendation for its management incentive plan.

1. Performance Enhancement Plan ("PEP").

Q. Do you agree with Mr. Smith's adjustments related to the PEP?

A. No, I do not. Mr. Smith's suggested sharing of the PEP program cost is based on an assumption that the program is an additional cost to the customers and that the specific goals or targets of the program are the only benefits and somehow equally benefit shareholders and customers. I disagree with the assumption that the program is an additional cost. I believe the PEP program costs are actually a net savings to customers. I also believe the program provides a valuable management tool to promote increased earnings, to promote additional cost savings, to motivate individual employees, to encourage groups of employees to work together to impact specific goals, and to aid in the retention of the higher-performing employees. All of these are ultimately benefits passed on to customers.

The goals or targets of the current PEP program are also heavily weighted toward providing benefits to customers. The program uses financial performance measures weighted at 30%, operational cost containment weighted at 30% and customer service goals at 40%. I would argue that the potential benefits of the current program goals and objectives alone would merit a much greater sharing than 50/50 based on an assumed benefit standard analysis.

However, I assert that because the program actually reduces the ultimate cost passed on to customers in the form of reduced payroll and benefits cost; it should actually be irrelevant which of the goals provides the greater benefit to whom in deciding recovery. It is counter-intuitive to penalize the Company for using an employee program that reduces costs passed on to the customers, that promotes increased safety, increased customer service, the reduction of other costs and increases the financial soundness of the Company. The Company is not proposing any sharing of the benefits of the program.

Q. Please further explain the PEP and some of the benefits to customers, the Company and to employees.

A. The overly-simplified description, "Incentive Compensation", is a little misleading and not an entirely accurate caption for the PEP program. A more accurate description of that program would be "a portion of an individual's fair and reasonable compensation put at risk to encourage and enhance group and individual performance". The "at risk compensation" portion is used on an individual basis to reward specific performance and provides management with an additional tool to encourage further cost savings, motivate individuals and to encourage employees to impact goals.

PEP is "at risk compensation" because there are no guarantees to individual employees that payment will be made. The Company's compensation philosophy is to pay at approximately 50% of market rate for its non-union employees. In benchmarking studies conducted by an outside consulting firm, non-union positions actual total average cash compensation (inclusive of incentives) was 8% below 50% of market (or at 42% of market) at UNS Gas. Therefore, the overall average PEP payouts are an integral part of the fair and reasonable compensation necessary to attract and retain employees. If the PEP program is eliminated, there would be considerable increased pressure on base compensation and it would eventually have to be increased toward market to allow the Company to compete in attracting and retaining a skilled workforce. It is not reasonable to assume that the Company would be able to continue to attract the best and brightest at compensation rates well below the market median. Furthermore, to stay competitive in attracting and retaining employees, the market is such that performance-based, lump sum cash awards are standard practice at 79% of companies today. So, Staff's recommendation will drive base compensation upward so that little to no compensation is "at-risk".

From the Company's and the customers' perspectives, there are many advantages to using a program like PEP, rather than just paying median market wages as base compensation. The most direct savings result because PEP is not part of base compensation; therefore employee costs such as: vacation pay, sick pay, long term disability, 401K matching, pension expense and other post-retirement benefits that are based on base pay are all reduced. There is the impact of reduced compounding wage increases that would be based on a higher base pay total. Consequently, there are the benefits produced from the specific goals tied to a portion of the employees' compensation, which are the benefit of the Company having greater flexibility to distinguish among and reward high-performers, to attract and retain more talented employees, and to mitigate the costs of training new employees by retaining key ones.

From the employee perspective, the proper mix of base wages and incentive pay has benefits. Individual employees are rewarded for contributing to the overall success of the organization and are allowed a way to directly participate in corporate success with a clear line of sight to goals. Employees can be acknowledged and rewarded for making a difference by exhibiting extra effort, working more hours on the job (for professionals not eligible for overtime pay), or supporting the program goals. Also, payment to individual non-union employees is discretionary, so talented and high-contributing employees can earn more through the program, which can be a motivating factor and can also lead to higher retention rates for more talented employees.

In short, the PEP benefits the ratepayer because of the net savings to the customer, the incentives it provides to motivate employees towards better serving the customer, and helps to attract and retain the best employees. Therefore, I disagree with Mr. Smith and the Company maintains its position to recover the PEP costs in rates.

2. <u>Officer's Long Term Incentive Program</u>.

Q. Do you agree with Mr. Smith's adjustments related to the Officer's Long Term Incentive Program?

A. No, I do not. Mr. Smith again simply applies an equal sharing of the cost methodology to this program and I disagree with the base assumptions behind such treatment. The costs at dispute here are primarily costs allocated to the Company from Tucson Electric Power Company ("TEP") for Executive oversight of UNS Gas.

These costs represent a portion of the Officers' total compensation, but are an integral part of a competitive compensation program. TEP also has a target level for determining compensation levels for Officers that is determined by the Board of Directors ("Board"). The Board has set that target at approximately median to 75% of a peer group of publicly-traded companies. The peer group is reviewed periodically and includes 16 electric and gas utility companies that are comparable to UniSource in terms of size as measured by annual revenues and market capitalization. The Board uses an outside consulting firm reporting directly to them to evaluate the compensation programs and levels, and to compare them to the peer group. The last study performed in October 2005 showed that TEP's Executives' total compensation program (including incentive programs) was 9% below that 75% mark of the peer group.

I would argue that instead of taking the position that this portion of "Incentive Compensation" is some additional cost to be parsed out equally to rate payers and to shareholders alike, it should be looked at in the context of its intended purpose. That purpose is to be a portion of a fair and reasonable compensation program that is necessary to attract, motivate and retain highly-skilled executives. Staff has not presented any evidence to demonstrate that the compensation and benefit packages of the Officers of TEP and UNS Gas are not reasonable. No portion of that package should be reduced without evidence being presented contradicting the evidence being provided by the Company.

3. <u>Deferred Compensation Plan</u>.

Q. Would you define the Deferred Compensation Plan as an Incentive Plan?

A. No, I would not. Below is an excerpt from the Company's response to Staff Data Request 5.72:

> <u>UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan")</u>
>
> The Deferred Compensation Plan allows participants (Directors, Officers and Managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis.

The plan is a program allowing Officers, Directors and Managers to defer recognition of a portion of their compensation for tax purposes and for retirement planning.

Q. Do you agree with Mr. Smith's adjustment to remove 50% of the Deferred Compensation Plan expenses allocated to UNS Gas?

A. No, I do not.

4. <u>Supplemental Executive Retirement Plan ("SERP")</u>.

Q. Please describe the SERP program.

A SERP is a retirement program that allows Officers to have proportionately equivalent retirement benefits to all other eligible employees. The amount that Mr. Smith is recommending be disallowed primarily represents benefit cost allocated to UNS Gas from TEP.

Q. Do you agree with Mr. Smith's adjustment to remove 100% of the SERP expenses allocated to UNSG?

A. No, I do not. I recognize that Mr. Smith has at least partially relied upon Commission's recent decision in the SWG rate case (Decision No. 68487) that disallowed the recovery of SERP expenses. However, a program like SERP should not be looked at in isolation nor should it be assumed that all factors are equal and comparable across different utilities. The SERP program is a portion of the compensation and benefits package made available to UniSource Officers. The level of compensation, incentives and benefits are all determined by the Board. The Board continually monitors those programs to determine if they are within the median to 75% range of TEP's peer group.

The reason a program like SERP is necessary is because of funding limits defined within the Internal Revenue Code. And those funding limits are set based on tax revenue collection needs, not on the point at which it is no longer fair to provide retirement benefits. They are not a guideline for how much is fair and reasonable as part of executive compensation. The evaluation of that should be the reasonableness of the compensation and benefit package as a whole. Below are the objectives of the compensation program for UniSource Executives:

> **<u>Objectives of the Executive Compensation Program</u>**
>
> We base our executive compensation policies and decisions with respect to our Named Executives on the achievement of the following objectives:
>
> 1. Attract, motivate and retain highly-skilled executives;
>
> 2. Link the delivery of compensation to the achievement of critical short- and long-term financial and strategic objectives, creation of shareholder value and provision of safe, reliable and economically available electric service;
>
> 3. Align the interests of management with those of our stakeholders and encourage management to think and act like owners, taking into account the interests of the public that the Company serves;
>
> 4. Maximize the financial efficiency of the program to avoid unnecessary tax, accounting and cash flow costs; and
>
> 5. Encourage management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance best practices.

The goals listed above define the structure of the plan, are proper and are in the best interest of both the Company and its customers. UNS Gas designed the plan so that it is competitive and fair to all parties. I further believe the plan has been effective in achieving optimal results for its customers as far as providing safe and reliable service, as well as being cost effective. The Board continually monitors these issues and hires outside consulting firms to help them evaluate these issues. I have provided substantial evidence in my Direct Testimony and here justifying these costs as related to providing service to UNS Gas customers. By contrast, Staff has not presented any evidence to demonstrate that the compensation and benefit packages of the Officers of UNS Gas are imprudent or not reasonable. So, I believe that SERP expense should not be reduced in this proceeding.

E. Emergency Bill Assistance (Staff Adjustment C-7).

Q. Mr. Dukes, do you agree with the recommendation of Mr. Smith regarding Emergency Bill Assistance expense?

A. Yes. Those expenses for emergency bill expense are more properly reflected in base rates and not in the Demand Side Management program funding.

F. Nonrecurring Severance Payment Expense (Staff Adjustment C-8).

Q. Mr. Dukes, do you agree with Mr. Smith's adjustment for Nonrecurring Severance Payment Expense?

A. No. I agree that in the Company's original payroll annualization adjustment an error was made related to the Nonrecurring Severance Payment "Credit".

Q. Why did you refer to it as a "Credit" instead of as an expense?

A. In 2004, an employee was severed from UNS Gas and as part of the severance was provided a payment in the amount of $52,387.56 (pre-tax) to be paid in 2005. That severance payment was "accrued" in December 2004 as an expense of UNS Gas and as a payable. So, it impacted the 2004 income statement. In January 2005, the accrual of the expense in 2004 was reversed. So a "Credit" was posted to payroll expense of UNS Gas in 2005 for ($52,387.56) and the payable accrued was eliminated. It is normal accounting practice to reverse accruals in the following month when the actual transaction is expected to be processed through a system such as accounts payables or payroll.

In this case, the check was issued through payroll but did not hit the books of UNS Gas, but instead actually hit the books of TEP. Because this error was so small, it was not found until the rate case was being prepared. So there was never an offsetting expense posted in 2005 to UNS Gas. What this means is that the payroll expense of 2005 was understated by $52,387.56. To put it another way, operating income was overstated by $52,387.56.

Q. What was the error in the Company's filed payroll annualization adjustment?

A. The payroll annualization adjustment proposed by the Company took test-year end employee levels and wages and annualized them to come up with the proper level of payroll expense to be included in the revenue requirement in this proceeding. Mr. Smith is not objecting to our calculation of non-overtime regular annualized payroll expense. Therefore, the annualized payroll expense is the level that we believe should be included in revenue requirements. However, the original adjustment by the Company subtracted the test-year non-overtime regular payroll expense after adding back the $52,387.56 severance expense. And by doing so, the Company understated the non-overtime regular payroll expense to be included in revenue requirement by $52,387.56. Below is a simple illustration of my point based on the numbers as originally filed by UNS Gas.

	(A)	(B)	(C=A+B)	(D)	(E=D-C)
	Actual Test Year Regular Wages	Severance Add-Back	**Adjusted** Test Year Regular Wages	Annualized Regular Wages Requested	Original Proposed Adj. to Regular Wages
	$5,095,757	$52,388	$5,148,145	$5,472,931	$324,786
Add Proposed Adj. to Test Year Actuals	$324,786				
Amount Currently Included in Company's Originally Filed Revenue Requirements	$5,420,543				

As shown above, the Company's original filed adjustment resulted in a revenue requirement that was $52,387.56 ($5,420,543 - $5,472,931) less than the annualized non-overtime regular payroll expense the Company calculated and not opposed by Staff or RUCO.

Q. How would Mr. Smith's proposed adjustment to remove the Nonrecurring Severance Payment Expense impact the revenue requirements?

A. It would further reduce the non-overtime regular annualized payroll expense being included in the Company's revenue requirements. In other words, if you accept his additional adjustment the revenue requirement would include $5,368,155 (pre-tax) of non-overtime regular annualized payroll expense, instead of the $5,472,931 (pre-tax). That would result in the Company having payroll expense set at $104,776 (pre-tax) below the annualized level it should be allowed to recover.

G. Overtime Payroll Expense (Staff Adjustment C-9).

Q. Do you agree with Mr. Smith's adjustment to the Company's proposed annualized overtime payroll expense?

A. Yes. Upon review of the proposed adjustment by Mr. Smith, I believe it is more reflective of the expected overtime levels that should be included in rates.

H. Nonrecurring FERC Rate Case Legal Expenses (Staff Adjustment C-11).

Q. Do you agree with Mr. Smith's adjustment to the Company's legal expense?

A. No, I do not. The specific rate case and its associated expenses referenced by Mr. Smith (El Paso Natural Gas) is, in fact, still an ongoing case. The Company had expenses throughout 2006 and into 2007 for continued legal support for the case and settlement. A host of additional issues not settled in the case require on-going FERC legal expenses. As further indication of the on-going nature of these legal expenses, in 2006 Transwestern Pipeline filed a rate case and we expect El Paso Natural Gas to file for increased operational restrictions in mid 2007 which will need to be litigated at FERC. Obviously, it does not make sense to exclude all legal expenses as non-recurring because the individual cases are not repeated year after year. The Company always incurs legal expenses each year as part of doing business. The objective should be to set legal expenses at a just and reasonable level that is reflective of how much is likely to be incurred annually. So, customers do not pay more than they should and the shareholders recover their cost.

In this particular case, I believe Mr. Smith's adjustment to test year legal expense to exclude $311,051 (pre-tax) would set the level of legal expense in the Company's revenue requirements well below an expected recurring level. That would leave legal expense in revenue requirements at only $177,329 (pre-tax), when actual incurred legal expenses were $373,174 in 2004, $488,380 in 2005 and $425,540 in 2006. Clearly, $177,329 does not reflect a reasonable level of legal expense annually.

Q. Do you have a suggested alternative adjustment to test-year legal expenses different than your Direct Testimony?

A. Yes, I do. I now recommend that the two-year average of 2004 and 2005 be used; which would be $430,777 (pre-tax). This amount is based on fixed, known and measurable expense levels and is clearly more indicative of actual recurring cost. That would equate to a reduction in the Company's original request of $57,603 (pre-tax).

I. <u>Worker's Compensation Expense (Staff Adjustment C-13)</u>.

Q. Do you agree with Mr. Smith's adjustment for Worker's Compensation Expense?

A. Yes.

J. <u>Membership and Industry Association Dues (Staff Adjustment C-14)</u>.

Q. Do you agree with Mr. Smith's adjustment for Membership and Industry Association Dues?

A. Partially. I do agree that a portion of the American Gas Association ("AGA") dues should have been excluded from the revenue requirement and I am not opposing the other exclusions proposed by Mr. Smith of $10,126 (pre-tax) related to payments made to other organizations. However, I believe the appropriate exclusion of the AGA dues should only be for the portions related to lobbying and marketing. I obtained those percentages from the AGA based on the AGA's 2007 budget and they were 2% and 1.39% respectively. That is just slightly less than the amounts used by RUCO in their adjustment to reduce AGA dues. I am including RUCO's adjustment in my revised revenue requirements.

K. Fleet Fuel Expense (Staff Adjustment C-15).

Q. Do you agree with Mr. Smith's adjustment to Fleet Fuel Expense?

A. I agree with part of his adjustment. I agree that it should be updated to reflect the most recent market cost of fuel and a portion of that increase should be allocated to construction. But the most recent prices that UNS Gas actually has paid is a more accurate determinant of actual fuel prices than relying on ArizonaGasPrices.com. It is more appropriate to reflect the cost that is most representative of the service territory in which the gas is used.

During the months of November 2006 through January 2007, the Company's average fuel cost per gallon of fuel was $2.48. If you update Mr. Smith's adjustment with the fuel cost recently incurred by UNS Gas, the additional fuel cost needed would be $61,069 (pre-tax). Overall, UNS Gas' request now reflects a $12,657 (pre-tax) reduction to its original filed adjustment.

L. Postage Expense (Staff Adjustment C-16).

Q. Do you agree with Mr. Smith's adjustment to Postage Expense?

A. No. First, Mr. Smith starts with actual book postage expense of $386,673 (pre-tax), which is understated by a prior period adjustment that was made during the test year to correct the pre-paid postage account. Prior to 2005, the Company had not been using a pre-paid postage account. When payments were made to the Postmaster to place a balance on the account associated with our postage meters, it was immediately expensed. This led to the 2003 balance sheet being understated by $99,668 in 2003 for postage paid for but not yet used. As of December 31, 2004, the postage paid but not yet used had dropped to $58,498 for a net decrease of $41,170. That meant that we used that portion of the postage dollars that had been prepaid and this amount should have been recorded as an expense in 2004. In 2005, the Company paid $452,798 to the postmaster and at the end of the year there was a $66,125 balance on the postage meters as paid postage but not yet used. That means that we increased the pre-paid postage level by $7,627 ($66,125 - $58,498). This then means that the actual postage expense for 2005 would be the $452,798 that we paid, less the $7,627 that we didn't use, or $445,171 in test-year postage expense.

So, $445,171 should be Mr. Smith's starting point, which when applied within Mr. Smith's adjustment calculation would result in pro forma postage expense of $476,960. This is more accurate than his proposed amount of $414,285, but is still not completely reflective of the normal and recurring level of postage expenses. This is the reason that the Company used a two-year average in the pro forma adjustment to posted expense Postage expense is not just dependent on customer count; it is also dependent upon the number of additional notices mailed, the weight of specific bill inserts, and other additional factors that affect the actual cost. The postage expense for 2006 – a known and measurable amount – was $553,648. This is $139,362 more than the Mr. Smith's suggested level. That is why I believe that the Company's proposed pro forma postage expense of $529,380 is the proper and reasonable amount of expense to include in the revenue requirement.

Q. What about Staff's assertion in response to UNSG Data Request No. 2-9 that the $66,125 of postage expense is not a test-year expense?

A. It is partially correct. Only $58,498 of it is related to actual test year expense. The $66,125 was an adjustment made during the test year to correct the prepaid postage account balance at December 31, 2005. As I explained above, the $66,125 represents the cash balance on the postage meters at the end of the test year. So it is properly accounted for as a rate base item within prepaid assets. And as I also describe above, there was *no* prepaid postage recorded on the balance sheet of UNS Gas as of December 31, 2004 for the $58,498 cash balance on the postage meters. So $58,498 was booked in 2005 as a *credit* to expense (even though it had nothing to do with 2005 expenses) and is related to prior periods, and $7,627 is credited to expense to reflect the increase in the postage meter balances within 2005. So test-year postage expense is $445,171 ($452,798 cash paid in 2005 and originally booked to expense, less $7,627 increase in the postage meter balance credited to expense) and the income statement only reflected expense of $386,673 because of the $58,498 credit related to a prior period (2004).

This situation is no different than if the Company received an invoice from the Postal Service saying we under-paid our account by $58,000 in 2003 and 2004. In that scenario, we would record a credit to cash and a debit to postage expense in 2005. Mr. Smith would have reviewed the invoice and said that test-year postage expense is overstated by $58,000 that is related to prior periods, and would have proposed an adjustment to remove it from test year expense. This is just the opposite and I am saying that if you are starting with test year expense, you must adjust it for the prior period impact. In addition, the prepaid balance in rate base is the amount of cash as of December 31, 2005 that the Company has prepaid to the Post Office and is also properly reflected as well.

III. REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

A. GIS Expenditures (RUCO Rate Base Adjustment 5 & Income Statement Adjustment 12).

Q. Do you agree with Ms. Diaz Cortez's recommendation to disallow the Company's request to include GIS expenditures as a regulatory asset and to recover that asset through amortization?

A. No. I provide numerous reasons earlier in my Rebuttal Testimony why I believe the Commission should allow the Company to recover these expenditures as requested. Ms. Diaz Cortez appears to not be questioning the benefits to the customers or the prudence of the expenditures, but is merely arguing that we did not get pre-approval to defer the cost. As I described earlier, there were extenuating circumstances that led to that outcome, we are asking the Commission to approve our request for ratemaking treatment.

I also disagree with Ms. Diaz Cortez's assertion that the Company has already recovered the GIS expenditures. First, it contradicts her own argument that the Company has deferred the cost for regulatory purposes without Commission approval. If we deferred the cost then we didn't recover it.

It is also an incomplete description of the circumstances. UNS Gas' last rate adjustment occurred in 2003 – to recover recurring expense levels based on a 2001 test year. The GIS expenditures were not anticipated at that time and so they were not included in the revenue requirement. But as I explained above, the GIS expenditures resulted directly from the Commission's Pipeline Safety Section. These costs occurred outside of the normal range or recurring expense and were not contemplated in the rate structure that is in effect. The Company has not recovered the GIS expenditures and will not recover them simply by expensing them within the GAAP books of the Company. If it could recover these costs by expensing them, then it would not have needed an accounting order.

Even if the Company had known in 2003 that it would end up expensing these costs – and asked for and received an accounting order allowing deferral of the expenditures for ratemaking purposes – the expenditures would still have been expenses for GAAP purposes. Without specific language in the accounting order saying that the Company would be allowed to recover the cost in the next rate case, GAAP would have required the Company to expense these costs.

It is not uncommon to have differing treatment of expenses for GAAP purposes and for ratemaking purposes. For example, in many electric cases, the overhaul cost for a turbine or boiler will be smoothed or amortized over an expected recurring cycle period. For GAAP purposes, those expenses will be recorded as incurred.

In addition, on Page 14 (lines 3-4) of her Direct Testimony, Ms. Diaz Cortez states that the Company's book net income was greater than $10.5 million in the test year. This is incorrect. The Company's operating income was over $10.5 million. Net income was actually just over $5 million for a return on ending equity of only 6.32%.

B. <u>Fleet Fuel Expense (RUCO Income Statement Adjustment 13)</u>.

Q. Do you agree with Ms. Diaz Cortez's Fleet Fuel Expense adjustment?

A. No, I do not. Ms. Diaz Cortez has taken a different approach than the Company or Mr. Smith. If I substitute the more recent cost per gallon of $2.48 actually incurred by the Company – that I discuss earlier in responding to Mr. Smith's adjustment to fleet fuel expense – and recalculate Ms. Diaz Cortez's adjustment, the pro forma is then a reduction to the Company's original adjustment of $41,079 (pre-tax). I believe that Mr. Smith's methodology is more appropriate once the fuel cost is updated. I have reflected a $12,657 reduction in my updated revenue requirement.

C. Corporate Cost Allocations (RUCO Income Statement Adjustment 16).

Q. Do you agree with Ms. Diaz Cortez's adjustment to reduce Corporate Cost Allocations?

A. Yes. Ms. Diaz Cortez discovered some additional non-recurring charges related to the attempted merger and has correctly proposed the removal of these costs.

D. Bad Debts – Uncollectibles (RUCO Income Statement Adjustment 17).

Q. Do you agree with Ms. Diaz Cortez's adjustment to reduce the Company's proposed Bad Debt Expense?

A. No. Ms. Diaz Cortez argues that the Company has overstated the pro forma bad debt expense because an historical write-off percentage was applied to adjusted test year revenue that included Griffith plant revenue and NSP customer revenue. Both of these revenues were excluded from the revenue requirement. Ms. Diaz Cortez went on to calculate a new pro forma bad debt expense by applying the Company's calculated write-off percentage to adjusted test-year revenue that excluded Griffith plant revenue and NSP customer revenues. The problem with this approach is that the Company's write-off percentage was calculated by dividing actual write-offs by actual revenues, that include NSP and Griffith plant revenues. Therefore, her adjustment understates the pro forma bad debt expense by applying an inconsistent rate.

E. <u>CWIP Property Taxes (RUCO Income Statement Adjustment No 18)</u>.

Q. Do you agree with Ms. Diaz Cortez's adjustment to reduce the Company's proposed Property Tax adjustment for CWIP included in rate base?

A. No. The adjustment is directly associated with the inclusion of CWIP in rate base as a plant item. Mr. Kentton C. Grant is the Company's witness in support of the inclusion of CWIP in rate base. Because CWIP should be included in rate base for the reasons Mr. Grant explains in his Rebuttal Testimony, the Company's property tax adjustment should not be adjusted as Ms. Diaz Cortez proposes.

F. <u>Out-Of-Period Expenses (RUCO Income Statement Adjustment 19)</u>.

Q. Do you agree with Ms. Diaz Cortez's adjustment for Out-of-Period Expenses?

A. Partially. Ms. Diaz Cortez identified some PriceWaterhouseCoopers ("PWC") invoices in test year expense that were for prior-period services. Accordingly, those should be removed from the test-year revenue requirement. However, her analysis was not symmetrical. Before 2006, PWC invoices for audit services were not accrued; they were progress-billed on a quarterly basis and were not materially different from year to year. Ms. Diaz Cortez is proposing to reduce test-year expenses for invoices expensed in 2005 for services provided in 2004. However, there are also invoices expensed in 2006 for services provide in 2005. These expenses are actually greater than the ones currently in the test year and would increase pro forma test-year expenses. The Company recommends RUCO's adjustment be rejected.

G. Legal Expenses (RUCO Income Statement Adjustment 20).

Q. Do you agree with Ms. Diaz Cortez's adjustment to test year Legal Expenses?

A. No, I do not. Ms. Diaz Cortez has made the same adjustment as Mr. Smith, which is to exclude the legal cost related to a FERC proceeding in the amount of $311,051 (pre-tax). As I discussed earlier, legal expenses paid to outside council are non-recurring on a case-by-case basis from year to year. However, there is a recurring level of necessary expense that must be built into revenue requirements to provide reasonable assurance of recovering recurring costs. As I mentioned earlier in my Rebuttal Testimony, we propose an amount based on the two-year average, reducing the Company's proposed test-year expense by $57,603 (pre-tax).

IV. REBUTTAL TO RUCO WITNESS RODNEY L. MOORE.

A. Worker's Compensation (RUCO Income Statement Adjustment 1).

Q. Do you agree with Mr. Moore's adjustment to Worker's Compensation?

A. Yes.

B. Incentive Compensation (RUCO Income Statement Adjustment 2).

Q. Do you agree with Mr. Moore's adjustment to Incentive Compensation?

A. No, I do not.

Q. Can you summarize Mr. Moore's reasoning for excluding Incentive Compensation?

A. Yes. Mr. Moore argues that the goals and objectives of the 2004 and 2005 PEP program were designed to provide a greater benefit to stockholders, that the 2005 payout was based on an arbitrary decision made by the Board, that the 2005 award is non-recurring and that he believes the program is discriminatory and only applies to a select group of non-union employees.

Q. Do you agree with any of the assertions that Mr. Moore makes concerning the Company's PEP plan?

A. No, and I will list the reasons. First, as I discussed earlier in response to Mr. Smith's Direct Testimony on PEP, I believe that the program actually saves the customers money in multiple ways even before the goals and objectives of the plan are taken into account. Second, the goals and objectives of the current plan are heavily weighted to the benefit of the customers. Furthermore, financial performance goals also strongly benefit customers. Even though the State of Arizona uses an historical test year to set rates, rates are set prospectively and the current PEP plan is what should be the basis for evaluation. Third, the 2005 award was not an arbitrary award approved by the Board, but was based on the remaining goals and objectives of the 2005 PEP that were achieved and not related to financial performance. The financial goal was missed primarily as a result of an unplanned outage at Springerville. This award was paid to real employees and was based on real efforts and real results they achieved. Fourth, the program applies to "all" non-union employees and I am concerned by Mr. Moore's use of the word discriminatory to describe the program. That word carries a negative connotation and could easily be misunderstood taken out of proper context. The Company would like to implement a PEP program for the union employees. But, their wages are collectively bargained and to date, the Union has rejected any proposals to put any portion of their fair-wage compensation "At Risk". The Union also has issues with any program that rewards employees in the same positions at differing rates based on their individual performance.

C. Postage Expense (RUCO Income Statement Adjustment 4).

Q. Do you agree with Mr. Moore's adjustment to postage expense?

A. No, I do not. Mr. Moore starts his calculation with test-year expense, similar to Mr. Smith, but inadvertently starts with only part of the test-year book expense. Also, as I describe in detail above in my rebuttal of Mr. Smith, the test-year book expense was understated by a prior-period credit and thus would need to be adjusted to $445,171 for this method to come up with an answer reflective of the recurring postage expense level. If I substitute this amount into Mr. Moore's calculation, I end up calculating a pro forma postage expense of $477,980. This is more accurate than his original calculation of $394,696, but is still not completely reflective of the normal and recurring level of postage expense. That is why I used a two-year average. As I discuss above, postage expense is not just dependent on customer count, but is also dependent on the number of additional notices mailed, weight of specific bill inserts, and a number of other additional matters that affect the actual cost. The postage expense for 2006 was $553,648. This is $158,952 more than the suggested level proposed by Mr. Moore. That is why I believe that the Company's proposed pro forma postage expense of $529,380 is the proper amount to be included in the revenue requirement

D. Customer Service Costs (RUCO Income Statement Adjustment 5).

Q. Do you agree with Mr. Moore's adjustment to Customer Service Costs?

A. No, I do not.

Q. Why did the Company transfer its call center functions over to a consolidated call center at TEP?

A. First, UNS Gas did not have a call center. The Company had various phone numbers for various locations within the Northern Arizona operation centers, and a handful of part-time customer representatives. Those customer representatives were limited by only having a few dedicated phone lines, no interactive voice response system ("IVR"), limited business hours (due to the limited staffing levels), limited back-up, and were not positioned to provide adequate customer service to a customer base of over 130,000 that is growing rapidly.

Basically, the system could not continue as it was configured and would have required a significant investment in new systems, phone lines, personnel, facilities and increased staffing and supervision levels to provide adequate customer service. The solution that made the most sense was to transfer the responsibilities to the TEP call center and take advantage of only paying a portion of the fixed cost for a system related to what is used rather than making all of the investment by UNS Gas.

Q. Have costs and service levels changed?

A. Yes. Costs in total have increased, but they would have had to increase. Otherwise, there would have been no system and very limited service levels. Service levels have improved significantly and call volume has almost doubled with the increased phone lines and representatives available to answer calls.

UniSource now has a consolidated Enterprise call center supporting UNS Gas, UNS Electric, Inc. and TEP. All share in paying the significant cost of supporting this center based on proportional usage. Previously, calls from UNS Gas customers were handled in each remote location, by a handful of employees picking up incoming calls in addition to other duties. The Company has made significant strides to improve customer service, including:

- 97% increase in calls handled from UniSource Energy Services, Inc. ("UES");
- 8.5 hours per day of coverage being expanded to 12 hours per day;
- An IVR capability being added;
- An assisted credit card payment option being added;
- Dedicated Customer Service Representatives being added;
- 237 trunk lines that are now available;
- One phone number for both gas and electric inquiries and for customers in Mohave and Santa Cruz Counties; and
- Call volume tracking is now available

So Mr. Moore is incorrect when he states that the same level of service exists today as in the pre-consolidation of the call center.

UniSource chose to integrate the call center function because of the investment and technology already in place at the existing Tucson call center facility, rather than duplicate a call center elsewhere. Any new investment in additional staff and technology equipment required to provide the above service levels would have been even more significant proportionately to UES than the existing allocation of costs.

The decision to use existing TEP systems and resources across a larger customer base resulted in more efficient use of existing assets and a lower combined cost of service to all UNS Gas customers, while providing a remarkable increase in service levels for UES customers and avoiding significant additional and duplicative investment at UES.

E. <u>Unnecessary Expenses (RUCO Income Statement Adjustment 6)</u>.

Q. Do you agree with Mr. Moore's adjustment for Unnecessary Expenses?

A. In general, I do not. There are $10,126 of cost within Mr. Moore's list that were also identified by Staff's witness Mr. Smith that I previously agreed to exclude from revenue requirements. However, Gary A. Smith will discuss the remaining expenditures that Mr. Moore is seeking to exclude as "Inappropriate" and "Unnecessary" in his Rebuttal Testimony. I would, however, like to comment on the proposed adjustment itself. Mr. Moore makes reference to UNS Gas' response to RUCO Data Request No. 4.01, which requested that the Company provide sufficient documentation for these expenses, which meet the 'necessary for the provisioning of gas service' criteria for inclusion in test-year operating expenses.

While this is a technically valid request, there has to be some consideration as to how this type of review is done and the cost versus benefit of such an analysis, from a reasonableness standard.

The original request included a list of 2,168 individual charges. Of those charges, approximately 65% were less than $50 and another approximate 25% were between $51 and $200. So about 90% of his request was to provide an explanation and documentation to support approximately 2,000 charges of $200 or less. Basically, Mr. Moore compiled a list of charges based on the vendor names that appeared to be a restaurant, hotel, store or airline. I cannot think of – and RUCO does not offer – any support for justifying its adjustment being in accordance with a reasonable professional standard or common practice. To ask the Company to justify over 1,400 transactions under $50 is an overly burdensome task that takes thousands of man-hours and costs a significant amount of money. Furthermore, the types of charges he is attempting to exclude are reviewed by the personnel's immediate supervisor and numerous controls are in place to ensure that they are valid charges incurred in the course of providing gas service to customers. Reviewing the policies, the controls and testing those items seems like a cost-effective and reasonable starting point; before asking for documentation of over 1,400 invoices of \$50 or less.

In responding to Mr. Moore's Data Request No. 4.01, I provided documentation for all advertising charges and all charges of \$1,000 or more. Of the charges of \$1,000 or more, Mr. Moore is proposing to exclude \$28,131.04. Further, \$24,288.27 out of the remaining \$197,394 Mr. Moore recommends exclusion of are charges comprised as an error in his computation because he used total invoice amount instead of the amount charged to UNS Gas. The remaining amount is for charges the Company did not provide documentation for, because it would have cost about \$75,000 based on the fully-loaded compensation levels for the personnel involved in undergoing such a process. So that is why I stated that by no reasonable professional standard should this be an acceptable method of compiling an adjustment and should not be allowed in this case. The fact is that meals and expenses such as the ones RUCO seeks to exclude are a typical and necessary part of doing business as Mr. Gary A. Smith explains in his Rebuttal Testimony. We would urge RUCO to set a realistic materiality level for its future requests.

F. **<u>Rate Case Expense (RUCO Income Statement Adjustment 8)</u>.**

Q. Do you agree with Mr. Moore's adjustment for Rate Case Expense?

A. No. Mr. Moore attempts to compare the UNS Gas rate case cost to SWG's most recent rate case and implies that SWG and UNS Gas are comparable companies. That assumption is flawed.

SWG has operations in Arizona, Nevada and southern California. SWG indirectly allocates its shared services to its Arizona operations based on a Massachusetts Formula. By contrast, TEP is a completely separate regulated utility. TEP directly allocates charges to UNS Gas for only the shared services that UNS Gas uses based on actual hours of services rendered.

For example, the SWG's Arizona operations gets approximately 55% of all shared service cost from "Corporate" whether they use it or not. In essence, the Arizona division has 50% of the accounting department, 50% of the plant accounting department, 50% of the rates/pricing department, 50% of the legal department, 50% of the payables department, 50% of the budgeting, etc. UNS Gas has none of these departments but instead is charged for resources actually used from TEP.

This is apparent looking at RUCO's response to the Company's Data Request No. UNSG 1-30d. In that response, RUCO states that SWG's allocated labor cost to its Arizona operations was 6.38% of total operating cost (excluding gas cost) and UNS Gas allocated labor cost was 1.75% of total operating cost (excluding gas cost).

Q. What have the direct allocations been to UNS Gas from TEP for shared services?

A. The direct allocations to UNS Gas from TEP for shared services (labor & burdens) were $863,254 in 2004, $965,823 in 2005, and $1,436,789 in 2006. The 2006 amount is inflated by the rate case expenses that equaled $476,602 in 2006 and were deferred as a regulatory asset; which left the remainder of normal activity at $960,187. This is equivalent to 2005 levels.

Q. What does all of that mean?

A. It means that SWG has these support services for doing a rate case built into their base rates and UNS Gas simply does not.

Q. Do you have any other comments regarding rate case expense?

A. Yes, as of the end of February 2007, the rate case deferral account had a balance of $786,556. This is $186,556 more than we had originally forecasted for this case. And since the case has hearings and an additional round of testimony remaining, it is possible that balance may reach $900,000, which is $300,000 more than we originally budgeted.

Q. What do you believe are the primary reasons causing the budget overage?

A. I see two primary drivers:

- The organization going through the first rate case for UNS Gas and thus having to research and address all issues for the first time; and
- The volume, complexity and magnitude of data requests received from Staff, RUCO and other Intervenors, which was probably also as a result of this being the first rate case for UNS Gas. For example, in SWG's most recent, case it received a total of 285 data request questions with 206 sub-parts. UNS Gas received 605 questions with

440 sub-parts. That is more than two times the number of requests that SWG received.

Q. Do you believe that UNS Gas should be allowed to collect all of these rate case expenses?

A. Most definitely. These are legitimate outside service costs incurred in the process of preparing and defending the UNS Gas rate case. In this particular instance, it will amount to about $300,000 being built into base rates for rate case expense. Even if you assume that 100% of that cost allocated from TEP that would only bring UNS Gas' allocated cost up to 2.5% total operating cost (excluding gas cost), that is still well below the SWG level 6.38%. The UNS Gas adjustment is basically adding an incremental amount to base rates for rate making support based on actual usage, versus just simply allocating portions of departments and charging them to UNS Gas whether they are used or not.

G. AGA Dues (RUCO Income Statement Adjustment 9).

Q. Do you agree with Mr. Moore's adjustment for AGA dues?

A. I have accepted Mr. Moore's adjustment to AGA dues.

H. Non-Recurring/Atypical Expenses (RUCO Income Statement Adjustment 10).

Q. Do you agree with Mr. Moore's adjustment for Non-Recurring/Atypical Expenses?

A. No, I do not. Mr. Moore is excluding certain training costs that were incurred during the year as non-recurring. These will be more specifically talked about in Company's witness Gary A. Smith's Rebuttal Testimony. But the Company is highly regulated, growing rapidly and continually adding new employees. So training is an on-going and primarily mandated process for the Company. Training costs will very likely continue to increase for the foreseeable future and removing any of these costs from the test year would not be appropriate.

I. <u>SERP (RUCO Income Statement Adjustment 11)</u>.

Q. Do you agree with Mr. Moore's adjustment for SERP?

A. No. I provide justification for SERP expenses in response to Mr. Smith's Direct Testimony on this subject.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DJD-1

UNS GAS, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2005

	As Filed 7/13/06 UNSG	As Filed 2/9/07 ACC Staff	As Filed 2/9/07 RUCO	Revised 3/16/07 UNSG	Summary	UNSG Witness
Original Cost Rate Base - Unadjusted	$149,791,159	$149,791,159	$149,791,159	$149,791,159		Kissinger
Rate Base Adjustments						
Acquisition Adjustment (RUCO Rate Base Adjustment No. 3)	35,277,589	35,277,589	35,028,702	35,277,589	RUCO adjusts the acquisition discount amortization claiming that the depreciation rates currently in use were not approved in the last rate case. UNSG is defending use of the rates. These were the rates used to derive depreciation expense in the Decision approving UNSG's current customer rates and were approved as such.	Kissinger
Southern Union Acquisition Premium	(17,053,753)	(17,053,753)	(17,053,753)	(17,053,753)	No adjustments	Kissinger
Griffith Power Plant	(5,254,086)	(5,254,086)	(5,254,086)	(5,254,086)	No adjustments	Kissinger
CWIP (Staff Adjustment B-1, RUCO Rate Base Adjustment No. 4)	7,189,231	-	-	7,189,231	Staff & RUCO exclude CWIP as not in service at test year end. UNSG defends its position for economic reasons and because the plant is in service prior to new rates being established. UNSG also asserts double jeopardy as there is $4.2 million in customer advances directly related to projects in this CWIP balance that have been included as a reduction of rate base.	Grant
Build-Out-Plant	(8,700,572)	(8,700,572)	(8,700,572)	(8,700,572)	No adjustments	Kissinger
Cares Asset	(1,662)	(1,662)	(1,662)	(1,662)	No adjustments	Kissinger
GIS Deferral (Staff Adjustment B-2, RUCO Rate Base Adjustment No. 5)	897,068	-	-	897,068	Staff & RUCO exclude the GIS expenditures from rate base primarily because UNSG did not get an accounting order from the Commission. They believe the costs are non-recurring and not eligible for rate base treatment. UNSG asserts that the costs were initially thought to be capital costs and the error was not detected until the fourth quarter of 2005. At that point the expenditures had already been made and it was impossible to request an accounting order in advance. The income statement impact did happen in the test year and no one argued that the costs were imprudent. The record shows the costs were at least partially incurred at the request of the Commission and benefit present and future customers.	Dukes
Pre-Acquisition Plant in Service (RUCO Rate Base Adjustment No. 1)	-	-	(6,990,677)	-	RUCO is claiming that UNSG cannot substantiate $3.1 million of plant additions added between 12/31/01 and 8/11/03. RUCO also contends that the level of accumulated depreciation as of 12/31/03 was incorrect based on their recalculation. UNSG strongly disagrees with RUCO's assertion.	Kissinger
Accumulated Depreciation (RUCO Rate Base Adjustment No. 2)	-	-	(2,855,454)	-	RUCO claims that since August 2003, UNSG has been using depreciation rates that were not approved by the Commission. UNSG is defending use of the rates. These were the rates used to derive depreciation expense in the Decision approving UNSG's current customer rates and were approved as such.	Kissinger
Customer Contributions	-	-	-	-	No adjustments	Kissinger
Other Rate Base (Y2K & Warm Spirit)	-	-	-	-	No adjustments	Kissinger
Accumulated Deferred Income Taxes (Staff Adjustment B-4)	2,807,892	3,003,228	2,807,892	2,807,892	Staff's differences are because of proposed rate base adjustments. RUCO did not adjust deferred taxes to synchronize with their proposed adjustments.	Kissinger
Working Capital (Staff Adjustment B-3, RUCO Rate Base Adjustment No. 6)	(3,291,503)	(2,520,543)	(2,091,351)	(2,592,809)	Staff & RUCO agreed with UNSG's lead/lag study after the correction supplied to them in response to Staff Data Request 5.76. The remaining differences arise primarily from varying adjustments and as a result of not completing a simultaneous equation to synchronize. The Company updated for adjustments accepted	Kissinger
Total Adjustments	11,870,204	4,750,201	(5,110,961)	12,568,898		
Pro Forma OCRB	161,661,362	154,541,359	144,680,197	162,360,056		
Requested Rate of Return	8.80%	8.12%	7.94%	8.80%	Staff recommends a 10% ROE and no hypothetical capital structure. RUCO recommends a 9.64% ROE and a 50/50 hypothetical capital structure. RUCO also calculated the cost of debt excluding debt issuance cost.	Grant
Required Operating Income	$14,223,179	$12,548,758	$11,480,374	$14,284,651		

UNS GAS, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2005

	As Filed 7/13/06 UNSG	As Filed 2/9/07 ACC Staff	As Filed 2/9/07 RUCO	Revised 3/16/07 UNSG	Summary	UNSG Witness
Original Operating Income - Unadjusted	$10,590,155	$10,590,155	$10,590,155	$10,590,155		Kissinger
Operating Income Adjustments						
Operating Revenue Adjustments						
Griffith Plant Operations	(865,152)	(865,152)	(865,152)	(865,152)	No adjustments	Dukes
Purchased Gas Cost & Gas Cost Revenue	(75,545,465)	(75,545,465)	(75,545,465)	(75,545,465)	No adjustments	Dukes
Customer Annualization (Staff Adjustment C-1, RUCO Operating Income Adjustment No. 14)	725,682	828,115	835,688	725,682	Both Staff & RUCO used year-end customer levels with no adjustments for the cyclical pattern of customer counts. UNSG used a slightly modified method to take into account the recurring customer level losses that happen each and every summer when customers leave the system.	Erdwurm
Weather Normalization (Staff Adjustment C-2, RUCO Operating Income Adjustment No. 15)	516,921	518,883	517,821	516,921	The differences here are primarily because the weather normalization adjustment starts with the annualized customer counts, revenues and sales.	Erdwurm
NSP Revenue & Gas Cost	(15,738,093)	(15,738,093)	(15,738,093)	(15,738,093)	No adjustments	Dukes
Cares	(203,181)	(203,181)	(203,181)	(203,181)	No adjustments	Dukes
Total Adjustments to Operating Revenues	(91,109,288)	(91,004,893)	(90,998,382)	(91,109,288)		
Operating Expense Adjustments						
Griffith Plant Operations	(164,614)	(164,614)	(164,614)	(164,614)	No adjustments	Dukes
Purchased Gas Cost & Gas Cost Revenue	(75,545,465)	(75,545,465)	(75,545,465)	(75,545,465)	No adjustments	Dukes
NSP Revenue & Gas Cost	(15,269,790)	(15,269,790)	(15,269,790)	(15,269,790)	No adjustments	Dukes
Payroll Expense (Staff Adjustment C-8 & C-9)	440,550	265,152	440,550	369,928	RUCO accepted UNSG's payroll adjustment. Staff adjusted UNSG's overtime levels and incorrectly adjusted an error that they found in our adjustment. UNSG accepted the overtime adjustment proposed by Staff and corrected the error in the original UNSG pro forma adjustment.	Dukes
Payroll Tax Expense (Staff Adjustment C-10)	25,907	12,551	25,907	20,567	Adjustments reflect changes to payroll expense.	Dukes
Pension & Benefits (RUCO Operating Income Adjustment No. 11)	54,594	54,594	(38,481)	54,594	RUCO is excluding SERP charges allocated to UNSG. UNSG believes that SERP is a part of a fair and reasonable executive compensation program and should not be excluded based on IRS limits established to maximize tax revenues.	Dukes
Post Retirement Medical	57,676	57,676	57,676	57,676	No adjustments	
Worker's Compensation (Staff Adjustment C-13, RUCO Operating Income Adjustment No. 1)	34,234	-	-	-	The Company is agreeing with proposed adjustments.	Dukes
Incentive Compensation (Staff Adjustment C-6, RUCO Operating Income Adjustment No. 2)	137,262	(130,163)	(141,486)	137,262	Staff excluded 50% of the test year "incentive" compensation and 100% of SERP expenses ; RUCO excluded all incentive compensation. UNSG is opposing all adjustments and asserts that programs like the Performance Enhancement Plan actually saves customers money and the other programs are part of a fair and reasonable compensation plan for the Officers and Directors of UniSource Corporation.	Dukes
Rate Case Expense (RUCO Operating Income Adjustment No. 8)	200,000	200,000	83,667	300,000	Staff proposed no change to the Company's original adjustment. RUCO compared UNSG to SWG and took the amount SWG got in their last rate case and adjusted it for inflation. UNSG is updating the record for the latest projected cost.	Dukes
Bad Debt Expense (Staff Adjustment C-3, RUCO Operating Income Adjustment No. 17)	317,758	319,021	222,175	317,758	Staff used the UNSG adjustment and inserted revised customer annualization revenues. RUCO recalculated using our historical write-off rate times pro forma revenues (excluding NSP and Griffith); this would be correct had they corrected the write-off percentage to reflect the exclusion of those revenues as well.	Dukes
Interest On Customer Deposits	16,507	16,507	16,507	16,507	No adjustments	
Fleet Fuel Expense (Staff Adjustment C-15, RUCO Operating Income Adjustment No. 13)	73,726	21,287	24,176	61,068	Both Staff & RUCO used calculations similar to the UNSG adjustment, except that RUCO used test year average fuel cost and Staff used a recent three-month average for the State of Arizona. UNSG accepts Staff's proposed method, but used the most recent three-month average actual fuel cost for UNS Gas instead of an Arizona average.	Dukes
Amortization of GIS Expenditures (Staff Adjustment C-5, RUCO Operating Income Adjustment No. 12)	(541,344)	(840,367)	(840,367)	(541,344)	Staff & RUCO excluded GIS, saying UNSG didn't have an ACC order to defer the cost. UNSG argues that the expense was booked in the test year and the Commission has authority to grant the Company's requested treatment.	Dukes
Out of Period Expenses (RUCO Operating Income Adjustment No. 19)	(43,743)	(43,743)	(64,863)	(43,743)	RUCO is excluding some PWC invoices for services provided in 2004 and expensed in 2005; however, RUCO did not look at the 2005 invoices expensed in 2006 that were essentially equivalent. UNSG recommends no change to its original adjustment.	Dukes

UNS GAS, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2005

	As Filed 7/13/06 UNSG	As Filed 2/9/07 ACC Staff	As Filed 2/9/07 RUCO	Revised 3/16/07 UNSG	Summary	UNSG Witness
Operating Expense Adjustments (cont'd)						
Year-End Accruals	(125,000)	(125,000)	(125,000)	(125,000)	No adjustments	
Advertising & Donations	(16,619)	(16,619)	(16,619)	(16,619)	No adjustments	
Postage Expense (Staff Adjustment C-16, RUCO Operating Income Adjustment No. 4)	142,707	27,612	(10,772)	142,707	Staff took test year expense and increased it for the postage rate increase. RUCO took a similar approach, but has a formula error in their calculation and also forgot to pick up other postage expense. Both parties ignored the fact that there was a $58k prior period adjustment in the test year that needed to be corrected in their starting number. When those issues are corrected, the approaches are very similar but, their proposed amount is inadequate when compared to the two year average cost and the actual 2006 cost.	Dukes
Cares	(16,899)	(16,899)	(16,899)	(16,899)	No adjustments	
Depreciation & Property Tax for CWIP (Staff Adjustment C-4, RUCO Operating Income Adjustment No. 18)	363,150	-	196,266	363,150	Staff excluded the adjustment for CWIP depreciation and property taxes completely. RUCO removed the property taxes and included the depreciation adjustment in their overall depreciation adjustment calculation. UNSG believes the CWIP in rate base should be allowed and disagrees with the proposed reductions.	Dukes
Gain on Sale of Prescott Property	(12,437)	(12,437)	(12,437)	(12,437)	No adjustments	
Corporate Cost Allocations (RUCO Operating Income Adjustment No. 16)	130,471	130,471	117,706	117,706	Staff made no adjustments. RUCO found an invoice we had missed related to the KKR acquisition.	Dukes
Customer Service Cost Allocations (RUCO Operating Income Adjustment No. 5)	325,422	325,422	(401,288)	325,422	Staff doesn't propose an adjustment. RUCO adjusts to an annualized incremental cost level based on having a handful of part-time CSR's, no system, inadequate phone lines and limited customer service. UNSG strongly opposes RUCO's adjustment.	Dukes
Depreciation Annualization	3,280	3,280	3,280	3,280	No adjustments	
Emergency Bill Assistance (Staff Adjustment C-7)	-	21,600	-	21,600	Staff argues should be in base rates and not in DSM surcharge. Company agrees with Staff's adjustment.	Dukes
Nonrecurring FERC Rate Case Legal Expense (Staff Adjustment C-11, RUCO Operating Income Adjustment No. 20)	-	(311,051)	(311,051)	(57,603)	Staff and RUCO exclude legal expenses related to the El Paso FERC case as non-recurring, despite the fact that we had legal expenses of $373k in 2004, $488k in the test year and $425k in 2006. This would put a two-year average right at our 2006 expense level; UNSG is proposing a two year average of 2004 & 2005 actuals.	Dukes
Membership & Industry Association Dues (Staff Adjustment C-14, RUCO Operating Income Adjustment No. 9)	-	(26,868)	(1,523)	(11,649)	Staff excludes 40% of AGA dues. RUCO excludes 3.6%. UNSG originally viewed this as immaterial; UNSG agrees with RUCO's adjustment.	Dukes
Pre-Acquisition Plant in Service Depr. Expense (RUCO Operating Income Adjustment No. 3)	-	-	(324,083)	-	RUCO reduces test year depreciation expense based on the recalculated plant in service balance. UNSG strongly opposes any exclusion of plant in service and strongly disagrees with RUCO's calculation of depreciation expense.	Kissinger
Unnecessary Expenses (RUCO Operating Income Adjustment No. 6)	-	-	(233,347)	-	RUCO excluded over 2,000 immaterial charges for items such as hotels, meals, flowers, training and etc. UNSG defends the changes as necessary in the course of providing gas service and takes issue with RUCO's burdensome approach.	Dukes
Nonrecurring Expenses (RUCO Operating Income Adjustment No. 10)	-	-	(2,584)	-	RUCO removed MARC training costs from expenses. UNSG is incurring ever-increasing employee levels, regulation and training requirements. It makes no sense to reduce any part of test year training cost.	Dukes
Property Taxes (Staff Adjustment C-12, RUCO Operating Income Adjustment No. 7)	1,591,370	1,511,080	1,282,061	1,591,370	Staff & RUCO adjusted to match their plant in service and also reached out an additional year to 2007 for assessment rate reductions. UNSG disagrees with these adjustments.	Kissinger
Income Taxes (Staff Adjustment "All C's"; RUCO Operating Income Adjustment No. 22)	(1,126,817)	(542,473)	703,573	(1,103,576)	Recalculations based on other adjustments.	
RUCO Operating Income Adjustment No. 20	-	-	(622,102)	-	RUCO error in Schedule RLM-7 as part of Operating Adjustment No. 20.	Dukes
Total Adjustments to Operating Expense	(88,948,114)	(90,079,236)	(90,969,227)	(89,008,145)		
Total Net Adjustments	(2,161,174)	(925,657)	(29,155)	(2,101,143)		
Adjusted Operating Income	$8,428,981	$9,664,498	$10,561,000	$8,489,011		
Operating Income Deficiency	$5,794,198	$2,884,261	$919,374	$5,795,640		
Gross Revenue Conversion Factor	1.6649	1.6370	1.6370	1.6370	There was an error in the UNSG original gross-up formula as filed.	Kissinger
Increase in Gross Revenue Requirement	$9,646,901	$4,721,446	$1,505,015	$9,487,462		

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

Karen G. Kissinger

on Behalf of

UNS Gas, Inc.

March 16, 2007

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Karen G. Kissinger. My business address is 4350 East Irvington Road, Tucson, Arizona, 85714.

Q. Are you the same Karen G. Kissinger that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. What is purpose of your Rebuttal Testimony?

A. I am specifically responding to the Direct Testimony from Rodney L. Moore from the Residential Utility Consumer Office ("RUCO") regarding (1) removing "unsubstantiated pre-acquisition gross plant and adjust understated accumulated depreciation" and (2) reducing test-year accumulated depreciation. I respectfully disagree with these adjustments for reasons I will explain later in my testimony.

Q. Are there other corresponding adjustments RUCO made as a result of the two adjustments you highlight above that you disagree with?

A. Yes. I also disagree with the resulting effects of Mr. Moore's adjustments on the Company's proposed test-year balances of Plant in Service and Accumulated Depreciation, and pro forma amounts of depreciation expense, amortization expense, and property taxes. I also disagree with Ms. Diaz Cortez's adjustment to accumulated amortization of the Acquisition discount proposed because she bases her adjustment on Mr. Moore's assertion that unapproved depreciation rates have been used by the Company. Finally, I have discovered numerous computational errors in the RUCO Schedules.

II. UNSUBSTANTIATED GROSS PLANT.

Q. Please explain your understanding of "unsubstantiated gross plant".

A. At Page 10 of his Direct Testimony, RUCO witness Mr. Moore proposes to reduce the Company's recorded balance of Plant in Service to remove what he characterizes as "Unsubstantiated Gross Plant". He states that the Company has not substantiated the end-of-test year Plant in Service balance it has proposed to include in rate base. As a result, he also is proposing corresponding reductions in Accumulated Depreciation, Depreciation Expense and Property Tax Expense.

Q. Do you agree with Mr. Moore's assertion of unsubstantiated plant balances and proposed adjustments relating thereto?

A. No, I do not.

Q. Why do you disagree with his assertion?

A. I disagree for several reasons. First, the acquisition of the Arizona gas assets of Citizens Communications Company ("Citizens") was accounted for in accordance with all applicable regulatory accounting requirements, and such accounting has received regulatory approval. I will explain this approval later in my testimony. Second, the Company's financial statements have been audited and a "clean" opinion obtained. A copy of the 2005 audit was attached to my Direct Testimony in this proceeding as Exhibit KGK-1. Third, we have provided Mr. Moore all of the Citizens' plant cost supporting documents that we have in our possession, and they cover substantially all of the plant additions from December 2001 (the end of the test year in the Citizens' Arizona Gas rate case that was in progress at the time of the acquisition) through June 30, 2006 (the end of the test year in this rate case). Finally, there was no regulatory requirement for Citizens to continue to provide information or resources past the acquisition date as there has been in other Commission orders approving utility acquisitions.

Q. What are the accounting requirements associated with the acquisition of assets from another utility?

A. A.A.C. R14-2-312-G requires all gas utilities regulated by the A.C.C. to maintain their books and records in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), Title 18 of the Code of Federal Regulations. Part 201 of Title 18 contains the requirements for natural gas companies. The specific accounting requirements associated with the acquisition of assets from another utility are set forth in Gas Plant Instruction No. 5. Exhibit KGK-2 (attached) is an excerpt from Instruction No. 5.

Q. Was that the accounting used by the Company with respect to the assets acquired from Citizens?

A. Yes, with one minor modification.

Q. What was that modification?

A. Pursuant to Paragraph 35 of the Citizens' Asset Acquisition Settlement Agreement approved in Decision No. 66028 (July 3, 2003), the Company transferred the balance of the Acquisition Discount from Account No. 114 Gas Plant Acquisition Adjustment to Acct. No. 108, Accumulated Depreciation.

Q. You state that the Company has received regulatory approval for the manner in which the acquisition was accounted. Please explain.

A. The USOA requires the acquiring utilities to file summaries of the proposed accounting for assets purchased from other utilities. On April 11, 2003, through our Washington counsel Troutman Sanders LLP, I sent a letter to the Secretary of the FERC describing the proposed accounting for the gas and electric assets acquired from Citizens. Exhibit KGK-3 is a copy of the relevant pages from that letter. At the time, our proposed accounting conformed to that required by Plant Instruction No. 5 of the USOA. The additional accounting reclassification of the Acquisition Discount to Accumulated Depreciation had not yet been required by the Commission.

In response to my letter, again through counsel, I received a letter dated July 17, 2003 from Mr. James K. Guest, Director of the FERC Division of Regulatory Accounting Policy, approving the proposed accounting entries. A copy of that letter is presented in Exhibit KGK-4 attached to my Rebuttal Testimony.

On February 9, 2004, I sent another letter to the Secretary of the FERC that contained the *actual* accounting entries for the Citizens acquisition. Included in that letter was the reclassification of the Acquisition Discount as the Commission mandated. The relevant portions of that letter appear on Exhibit KGK-5 attached to my Rebuttal Testimony.

Throughout the process of acquiring the Citizens assets and obtaining the requisite approvals, the recording of plant account balances and depreciation reserves on the books of UNS Gas as they appeared on the books of Citizens as of the acquisition date was not only required under the applicable accounting, but was what actually was done and what was reported to, and approved by, the FERC.

Q. What documents have you provided Mr. Moore in connection with the recorded plant cost of UNS Gas?

A. In the response to RUCO Data Request No. 1.08, we provided an analysis of the plant additions, adjustments, and retirements for UNS Gas covering the period August 2003 through December 2005. As a follow up to that request, RUCO issued Data Request No. 2.19 asserting "unsubstantiated plant additions" of $28,649,085 occurring between October 29, 2002 (the date of the Acquisition Agreement) and August 11, 2003 (the date that the acquisition was completed), and soliciting a reconciliation of plant additions occurring during that indicated period.

In responding to this request, and reviewing the various plant accounting data sources, it was determined that the $28.6 million amount appearing in the Data Request could only be arrived at as follows:

Plant in Service Acquired on 8/11/2003	$248,032,064
Adjusted Rate Base plant at 12/31/2001 per the Settlement Agreement	219,383,559
Difference	$ 28,649,085

It was clear that the amount of "unsubstantiated" plant additions was computed as the difference between two amounts that were not consistent with each other, and actually reflected a time period different from that identified in the request. One number represented the recorded per books plant acquired from Citizens while the other was an *adjusted* plant component of the rate base appearing in the Citizens rate case that was in progress at the time of the acquisition.

In response to RUCO Data Request No. 2.19, we provided a reconciliation of the recorded plant balances at December 31, 2001 with the final adjusted plant amounts in the Citizens' rate case application with those implicit in the Settlement Agreement approving the acquisition. Moreover, we provided an analysis of the ending balances of Plant in Service and Construction Work in Progress as well as total capital expenditures as reported in the monthly financial reports of Citizens' Arizona Gas for the period December 2001 through August 2003. We noted that the content of these monthly reports was substantially reduced after June of 2003 as Citizens worked toward completing the closing of its accounting office in New Orleans – shortly after the acquisition by UniSource Energy Corporation ("UniSource") was completed. Accordingly, the analysis did not include the balances of Plant in Service or Construction for July 31st and August 11th. However, we also included with our response to RUCO Data Request No. 2.19 were the fixed asset and accumulated depreciation files for UNS Gas and the combined financial statements for calendar year 2002. So, UNS Gas provided evidence substantiating the plant additions – the $28,649,085 – RUCO questions in its Direct Testimonies. We therefore disagree with RUCO's adjustment Mr. Moore advocates for in his Direct Testimony at pages 10 through 12.

Q. You state that there was no regulatory requirement for Citizens to provide information or resources past the acquisition date. Please explain.

A. In some previous Commission orders approving utility acquisitions, in anticipation of future regulatory matters involving acquired utility assets, the Commission has imposed specific requirements on the selling utility to provide certain documents and records that may have future ratemaking or other regulatory value. For example, Decision No. 57647 (December 2, 1991), which approved the acquisition by Citizens of the Southern Union Gas Company operation in Northern Arizona, contains the following language beginning at line 6 of page 14:

> IT IS FURTHER ORDERED that Southern Union Gas Company shall provide Citizens Utilities Company all historical operating data for its Arizona properties for the last 5 years, and Citizens shall retain the data for a 10-year period.

Similar requirements are contained in other Commission orders. Neither the acquisition Settlement Agreement nor Decision No. 66028 approving the acquisition contains any such language similarly obligating Citizens or UniSource.

Q. What is your recommendation to the Commission?

A. There is clearly no basis for the Commission to accept in this proceeding Mr. Moore's recommendations with respect to "unsubstantiated" plant costs. It should be rejected.

III. <u>UNAUTHORIZED DEPRECIATION RATES</u>.

Q. Please explain the RUCO assertion that the Company has been using unauthorized depreciation rates.

A. At page 13 of his Direct Testimony, RUCO witness Mr. Moore proposes an adjustment to Accumulated Depreciation, alleging that the Company has been using book depreciation rates that the Commission has not approved. Specifically, Mr. Moore states on page 13, line 21, of his Direct Testimony that the Settlement Agreement approving the acquisition of the former Citizens' Arizona gas assets by UniSource "did not authorize a change in depreciation rates it had established in Decision No. 58664."

Mr. Moore has recomputed the Accumulated Depreciation component of rate base using the rates approved in Commission Decision No. 58664 (June 16, 1994). The allegation of unapproved depreciation rates also affects Mr. Moore's adjustment to the Company's proposed level of Property Tax Expense and RUCO witness Ms. Diaz Cortez' adjustment to test-year pro forma Amortization Expense.

Q. Do you agree with Mr. Moore?

A. No I do not. While I do agree that there is no specific language in either the Settlement Agreement or Decision No. 66028 issued in July 2003 approving the Settlement, I can clearly demonstrate that the rate increase the Commission approved in connection with that Decision reflects a revenue requirement that includes a depreciation expense component based on new depreciation rates being sought in the Citizens' Arizona gas rate case in progress at that time.

Q. Please demonstrate your assertion that the depreciation rates currently being used are implicit in the current service rates authorized for UNS Gas.

A. Included in the application filed by Citizens for its Arizona Gas operations in Docket G-1032A-02-0598 – the rate case that was in progress at the time of and specifically resolved by the Settlement Agreement – was a request to combine Citizens' Northern Arizona and Santa Cruz Gas Divisions into a single entity. The rate application also included a request to implement new depreciation rates. That request was supported by the testimony and exhibits sponsored by Citizens' consultant Dr. Ronald White. Exhibit KGK-6 (attached) is the Executive Summary of his testimony filed by Dr. White in that rate case. Exhibit KGK-7 (attached) summarizes the new depreciation rates proposed by Dr. White.

Citizens' witness Mr. Kevin Doherty sponsored an adjustment in that 2002 rate case to annualize test year depreciation expense, using the end-of-test-year balances of Plant in Service and the new depreciation rates recommended by Dr. White in that docket. Both Dr. White's aforementioned Executive Summary and the Direct Testimony of Mr. Doherty clearly indicate that the proposed new depreciation rates were used to calculate the pro forma depreciation expense. Exhibit KGK-8 (attached) is an excerpt from Mr. Doherty's testimony.

Exhibit KGK-9 (attached) is a summary of the operating expense adjustments Citizens proposed in the 2002 rate case. As may be seen in column 10 on page 1, the depreciation adjustment totaled ($2,005,664). Because there were no other adjustments proposed to depreciation and amortization expense, Column 12 on page 2 also shows ($2,005,664) at Line 22.

Exhibit KGK-10 (attached) is the Statement of Operating Income filed in the 2002 Citizens' Arizona Gas rate case. Line 22 thereof shows a per-books test-year total of $8,085,696 for depreciation and amortization expense, which after reflecting the ($2,005,664) becomes an adjusted $6,080,032. Total adjusted operating expenses are reported as $29,859,584 in Column 8 at Line 25.

Exhibit KGK-11 (attached) is the Appendix B – Schedule 1 that was attached to the Settlement Agreement. The purpose of this schedule is to present the positions of Citizens and UniSource on the in-progress rate case and the final agreed Settlement amount. The Operating Expenses are presented on Line 17, with the corresponding percentage increase in annual revenues shown on Line 29. As indicated, Citizens had requested a 28.93% increase in service rates, with the Settlement providing for a 20.92% increase. As previously stated the Citizens rate filing proposed an annual level of operating expenses totaling $29,859,584 whereas the Settlement provided for $28,883,183. *None* of the $976,401 difference between Citizens' request and the Settlement amount relates to depreciation expense computed by any rates other than those new requested book depreciation rates recommended by Dr. White.

Exhibit KGK-12 (attached) includes pages excerpted from Decision No. 66028 approving the Settlement. As indicated on the first page (page 17 of the Order), the $15,191,276 (20.92%) rate increase reported on KGK-11 is acknowledged. Page 31 of that Decision –

the second page of Exhibit KGK-12 – clearly indicates the Commission's acceptance of the agreed-upon annual rate increase.

Q. What do you conclude from your analysis?

A. It is clear that the annual pro forma depreciation expense computed by Citizens and based on Dr. White's recommended new depreciation rates are in fact implicit in the revenue requirement underlying UNS Gas' current service rates approved in Decision No. 66028. While neither the Settlement nor the Commission Decision approving the Settlement specifically address the request for approval of new depreciation rates, my analysis definitively shows that the rate increase agreed to by all parties reflects the requested new rates.

Q. Would it be proper to use any other rates for accruing depreciation than those requested by Citizens?

A. It would not.

Q. What is your recommendation to the Commission?

A. I respectfully recommend that it consider the analysis I have provided and reject Mr. Moore's assertion that unauthorized depreciation rates have been used by the Company. Moreover, all of the adjustments proposed by RUCO witnesses that are based on the assertion of unauthorized depreciation rates should be similarly rejected.

IV. <u>COMPUTATIONAL ERRORS</u>.

Q. You have stated that you have discovered errors in the schedules of RUCO witnesses. Is that correct?

A. Yes. Several of the schedules contain conceptual or mathematical errors.

Q. Please explain some of those errors.

A. Schedule RLM-4 supporting RUCO's proposed adjustments for the effects of what it characterizes as "unsubstantiated plant additions" and "unauthorized depreciation rates" is flawed because it contains computational errors due to the use of incorrect plant account balances and incorrect depreciation rates. I refrain from elaborating to avoid overshadowing the fact that, as I have already clearly shown in this rebuttal testimony, the proposed adjustments are totally without merit and should be categorically rejected.

Q. Are there other errors that you wish to bring to the Commission's attention?

A. Yes. There are serious flaws in the calculation of the income taxes.

Q. Please explain.

A. RUCO has recommended numerous adjustments to rate base and operating income, yet it leaves unchanged the deferred income tax expense and accumulated deferred income taxes reflected in the Company's filing. As more fully described in my Direct Testimony, typically, the most significant book-tax difference recognized in regulatory accounting and ratemaking is that associated with depreciation, where <u>tax</u> depreciation is computed based on shorter lives and accelerated methods as compared with <u>book</u> depreciation, which is based on service lives and a ratable straight-line method. This timing difference gives rise to deferred income tax expense which is accumulated in a balance sheet account that is deducted from rate base in ratemaking. To the extent that any book cost (i.e. depreciation) proposed by the Company in a rate filing that is part of a timing difference that the Company has been permitted to include in deferred income tax expense for ratemaking is adjusted, there must be a corresponding change in deferred income tax expense and accumulated deferred income taxes, as well as current income taxes. As a result of its assertion of "unsubstantiated plant additions" and "unauthorized depreciation rates" RUCO has proposed adjusting depreciation expense, accumulated depreciation, and <u>current</u>

income tax expense, but there are no corresponding adjustments to <u>deferred</u> income tax expense or accumulated deferred income taxes. Its proposal is incomplete, however, as previously stated, that should not overshadow the fact that their overall assertion of "unsubstantiated plant" and "unauthorized depreciation rates" are totally without merit.

There is another error in the RUCO filing. It is also noteworthy that, in ratemaking, there is an implicit interrelationship between cash working capital, rate base, current income tax expense, and the synchronized tax deduction for interest that must be recognized and properly accounted for. The Commission has adopted a long-standing policy that the deduction for interest in computing income taxes should be synchronized; that is, the amount of interest used in computing income tax expense should be that amount of interest implicit in the overall revenue requirement. Synchronized interest is computed by multiplying rate base by the weighted cost of debt. Both synchronized interest and current income taxes are elements of the calculation of cash working capital. Cash working capital is a component of rate base. To properly compute each of these elements of revenue requirements, it is necessary to perform an algebraic exercise using simultaneous equation. Such a computation was performed by the Company and is reflected in its filing. In reviewing the RUCO filing, there is no evidence that such a computation was performed.

V. <u>WORKING CAPITAL</u>.

Q. Have any of the adjustments accepted by the Company in its Rebuttal Testimony impacted the Company's calculation of working capital?

A. Yes. A number of the adjustments will have an impact on working capital. A revised amount for working capital is shown in Mr. Dukes Exhibit DJD-1. This adjustment reflects the composite impact of all the adjustments accepted by the Company.

Q. Does that conclude your rebuttal testimony?

A. Yes it does.

EXHIBIT

KGK-2

5. *Electric Plant Purchased or Sold.*

A. When electric plant constituting an operating unit or system is acquired by purchase, merger, consolidation, liquidation, or otherwise, after the effective date of this system of accounts, the costs of acquisition, including expenses incidental thereto properly includible in electric plant, shall be charged to account 102, Electric Plant Purchased or Sold.

B. The accounting for the acquisition shall then be completed as follows:

(1) The original cost of plant, estimated if not known, shall be credited to account 102, Electric Plant Purchased or Sold, and concurrently charged to the appropriate electric plant in service accounts and to account 104, Electric Plant Leased to Others, account 105, Electric Plant Held for Future Use, and account 107, Construction Work in Progress—Electric, as appropriate.

(2) The depreciation and amortization applicable to the original cost of the properties purchased shall be charged to account 102, Electric Plant Purchased or Sold, and concurrently credited to the appropriate account for accumulated provision for depreciation or amortization.

(3) The cost to the utility of any property includible in account 121, Nonutility Property, shall be transferred thereto.

(4) The amount remaining in account 102, Electric Plant Purchased or Sold, shall then be closed to account 114, Electric Plant Acquisition Adjustments.

Source: FERC <u>Uniform System of Accounts</u>

EXHIBIT

KGK-3

TROUTMAN SANDERS LLP

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April 11, 2003

FILED
OFFICE OF THE
SECRETARY
03 APR 11 PM 2:20
FEDERAL ENERGY
REGULATORY COMMISSION

03 Apr 11

The Honorable Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: *Citizens Communications Company and UniSource Energy Corporation*
Docket No. EC03-54-000

Dear Ms. Salas:

Enclosed for filing are an original and fourteen copies of proposed accounting entries for the transaction between UniSource Energy Corporation and Citizens Communications Company. The companies have provided this information to the Office of the Chief Accountant, and are also filing this information at the request of FERC Staff.

Please contact the undersigned if you have any questions regarding this filing.

Sincerely,

Antoine P. Cobb

Attorney for Citizens Communications Company and Tucson Electric Power Company

Enclosures

Cc: Ken Anderson, Office of the Chief Accountant

UniSource Energy

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Tucson, Arizona 85702

Area Code 520
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April 11, 2003

The Honorable Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Citizens Communications Company and UniSource Energy Corporation
Docket No. EC03-54-000

Dear Ms. Salas:

On October 29, 2002, UniSource Energy Corporation (UniSource) entered into an agreement with Citizens Communications Company (Citizens) to acquire Citizens' electric and gas distribution & transmission systems located and operated in the state of Arizona. The parties have requested approval from the Commission for this acquisition in Docket No. EC03-54-000.

Under the proposed structure of the transaction, UniSource has created a wholly-owned subsidiary UniSource Energy Services. Two wholly-owned subsidiaries of UniSource Energy Services will be organized to own the electric and gas assets acquired from Citizens. For purposes of this filing, the operating companies that will own and operate the gas and electric systems will be referred to as GasCo and ElecCo, respectively.

As requested, we are providing the proposed accounting treatment that will be recorded on the books of GasCo and ElecCo in connection with this acquisition. The information provided is based on financial information as of October 31, 2002, which is the accounting period ending nearest to the agreement date. The actual entries will not be known until the transaction is completed in the summer of 2003, however the proposed accounting treatment should not differ significantly from the final entries.

GasCo provides its proposed journal entries on Attachment No. 1 to record the initial capitalization of GasCo, the acquisition of Citizens' Arizona gas assets, the clearing of Account 102, *Gas plant purchased or sold* and the clearing of Account 114, *Gas plant acquisition adjustments*.

ElecCo provides its proposed journal entries on Attachment No. 2 to record the initial capitalization of ElecCo, the acquisition of Citizens' Arizona electric assets, the clearing of Account 102, *Electric plant purchased or sold* and the clearing of Account 114, *Electric plant acquisition adjustments*.

I. SUMMARY OF PROPOSED JOURNAL ENTRIES

A. GasCo, Attachment No. 1

Journal Entry No. 1 records the initial capitalization of GasCo with sufficient cash to purchase the assets. The anticipated capital structure is 40% common stock equity and 60% long-term debt. Journal Entry No. 2 reflects the acquisition of the gas system assets. Journal Entry No. 3 reflects the clearing of Account 102, *Gas plant purchased or sold* to the appropriate plant accounts. Journal Entry No. 4 reflects the clearing of Account 102, *Gas plant purchased or sold* to Account 114, *Gas plant acquisition adjustments*. Entry No. 5 reflects the reclassification of the balance in Account 114 to Account 108, *Accumulated provision for depreciation of gas utility plant*.

GasCo believes its proposed accounting for the clearing of Accounts 102 and 114 is consistent the with the Commission's Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act[1] and past accounting decisions.

B. ElecCo, Attachment No. 2

Journal Entry No. 1 records the initial capitalization of ElecCo with sufficient cash to purchase the assets. The anticipated capital structure is 40% common stock equity and 60% long-term debt. Journal Entry No. 2 reflects the acquisition of the electric system assets. Journal Entry No. 3 reflects the clearing of Account 102, to the appropriate plant accounts. Journal Entry No. 4 reflects the clearing of Account 102, *Electric plant purchased or sold* to Account 114, *Electric plant acquisition adjustments*. Entry No. 5 reflects the clearing of Account 114 to Account 108, *Accumulated provision for depreciation of electric utility plant*.

ElecCo believes its proposed accounting for the clearing of Accounts 102 and 114 is consistent the with the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act[2] and past accounting decisions.

C. Proforma Financial Statements, Attachment No. 3

The effect of the proposed journal entries on the financial statements of GasCo and ElecCo is shown in Attachment 3. The financial statements provided are a proforma October 31, 2002 balance sheet and a proforma income statement for the ten months ended October 31, 2002.

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[1] 18 CFR Ch. 1, Part 201
[2] 18 CRF Ch. 1, Part 101

II. SUPPORT FOR PROPOSED JOURNAL ENTRIES

A. Background of Commission Accounting Requirements

The Commission has put into place accounting systems that recognize, measure, and report economic consequences in accordance with the standards that are prescribed for rates. Under the accounting model, the Commission has a longstanding policy of requiring that a jurisdictional utility classify any differences between the purchase price of utility plant acquired in connection with an acquisition and the related original cost of those assets as an acquisition adjustment in Account 114, *Gas/Electric plant acquisition adjustments*. In those cases in which the purchase price is less than the original cost of the related assets, the so-called "negative" acquisition adjustment, the Commission has directed jurisdictional utilities to reclassify the negative amounts to Account 108, *Accumulated provision for depreciation of gas/electric utility plant*.

B. Accounting for the Acquisition Adjustment

The proposed $65,087,462 balance for GasCo recorded initially as a credit to Account 114 represents the excess of the book value of the gas assets purchased over the acquisition price. GasCo and ElecCo proposes to reclassify these "negative" acquisition adjustments to Account 108. The proposed $100,350,725 balance for ElecCo recorded initially as a credit to Account 114 represents the excess of the book value of the electric assets over the acquisition price. GasCo and ElecCo proposes to reclassify these "negative" acquisition adjustments to Account 108.

As support for this accounting, GasCo and ElecCo rely on the accounting treatment for business combinations under generally accepted accounting principles (GAAP). The Financial Accounting Standards Board (FASB) recently revised the accounting standards for business combinations. The revised standards require that the purchase price of the assets be allocated among the assets based on the fair market value of the assets acquired. The fair market value of the gas and electric system assets acquired is equal to the acquisition price agreed to by the parties. After allocating the acquisition price to those assets carried on the balance sheet at fair market value (e.g., cash, accounts receivable, etc.) the remaining balance reflects the fair market value of the gas and electric plant assets acquired. The reclassification of the "negative" acquisition adjustment to Account 108 results in a book value equal to the fair market value of the assets acquired.

Over the years the Commission has emphasized its overall objective and goal of minimizing the differences between accounting and financial statement presentation in reports prepared for the FERC, stockholders, and others. Therefore, GasCo believes it appropriate to account for "negative" acquisition adjustments consistent with the revised GAAP for accounting for business combinations. Therefore, GasCo requests approval for the reclassification of the "negative" acquisition adjustment to Account 108.

If you require additional information please contact me at (520) 745-3122.

Very truly yours,

Karen G. Kissinger

Karen G. Kissinger
Vice President, Controller and
Chief Compliance Officer

KGK/gb

Attachment No. 1

GasCo.
Proposed Journal Entries for the Purchase of Gas Assets

	FERC Acct	Debit	Credit
1			
Special Deposits	134	142,379,105	
Common Stock	201		56,951,642
Bonds	222		85,427,463

To record the debt and equity transactions for the purchase of the gas assets.

	FERC Acct	Debit	Credit
2			
Gas Plant Purchased	102	136,678,230	
Cash and Cash Equivalents	131	145,639	
Special Deposits	134		142,379,105
Customer Accounts Receivable	142	6,950,869	
Other Accounts Receivable	143	323,204	
Reserve for Doubtful Accounts	144		101,570
Materials & Supplies	154	617,876	
Prepayments	165	89,460	
Other Deferred Debits	186	10,767,768	
Accounts Payable	232		5,071,358
Customers' Deposits	235		1,923,891
Interest Accrued	237		59,482
Customer Advances for Construction	252		6,237,640

To record the acquisition of gas plant assets.

	FERC Acct	Debit	Credit
3			
Gas Plant Purchased	102		201,765,692
Plant in service	101	234,543,969	
Construction Work in Progress	107	4,185,909	
Accumulated Depreciation	108		58,280,763
Gas Plant Acquisition Adjustment	114	21,316,577	

To record the original cost and related accumulated depreciation of the acquired gas plant assets.

	FERC Acct	Debit	Credit
4			
Gas Plant Purchased	102	65,087,462	
Gas Plant Acquisition Adjustment	114		65,087,462

To close out the balance in account 102, Gas Plant Purchased, to account 114, Gas Plant Acquisition Adjustment.

Attachment No. 1 - continued

GasCo.
Proposed Journal Entries for the Purchase of Gas Assets

5				
	Gas Plant Acquisition Adjustment	114	43,770,885	
	Accumulated Depreciation	108		43,770,885

To reclassify the "negative" acquisition adjustment to account 108, Accumulated Provision for Depreciation of Gas Plant.

EXHIBIT

KGK-4

In Reply Refer To:
OED-DRAP
Docket No. AC03-48-000

July 17, 2003

Troutman Sanders LLP
Attention: Mr. Antoine P. Cobb
Attorney for Citizens Communications Company
401 9th Street, NW., Suite 1000
Washington, DC 20004-2134

Thank you for your April 11, 2003 letter, filed on behalf of Citizens Communications Company (Citizens) and UniSource Energy Corporation (UniSource), advising us of their proposed accounting entries in connection with UniSource's acquisition of Citizens' electric and gas distribution and transmission systems located in the state of Arizona. The transaction was approved under delegated authority in Docket No. EC03-54-000.[1]

We accept your proposed journal entries for filing.

UniSource proposes to transfer the original cost and related accumulated depreciation for the electric and gas assets from Citizens' books consistent with the requirements of Electric and Gas Plant Instruction No. 5.F. [2] UniSource proposes to record in Account 114, Electric or Gas Plant Acquisition Adjustments, a negative acquisition adjustment of $65,087,462 for the gas assets and a negative acquisition balance of $100,350,725 for the electric assets. UniSource will transfer from the seller's books a $21,316,577 balance in Account 114 and use the amount to offset the $65,087,462 negative acquisition adjustment for the gas assets. [3] UniSource will transfer

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[1]103 FERC ¶ 62,100 (2003).

[2]18 C.F.R. Parts 101 and 201 (2003).

[3]In an e-mail dated June 5, 2003, you state that the $21,316,577 balance in Account 114 represents an acquisition adjustment that resulted from Citizens' purchase of the gas assets from Southern Union in 1992 at an amount in excess of the net book value.

the balances in Account 114 to Account 108, Accumulated Provision for Depreciation of Electric or Gas Utility Plant.

Citizens proposes to remove the original cost and related accumulated depreciation from its books consistent with Electric and Gas Plant Instructions No. 5.(F). Citizens proposes to recognize in Account 421.2, Loss on Disposition of Property, a $65,087,462 loss on the sale of the gas assets and a $224,992,547 loss on the sale of the electric assets. A portion of the loss ($124,641,822) on the sale of the electric assets represents a write-down of the remaining Purchase Power Fuel Adjustment Clause (PPFAC) balance. [4]

This letter order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this letter order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

James K. Guest
Director, Division of Regulatory
Accounting Policy

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[4]The amount will not be recovered in future rates in accordance with agreements with the Arizona Public Utilities Commission.

EXHIBIT

KGK-5

UniSource Energy

4350 East Irvington Road, Post Office Box 711
Tucson, Arizona 85702

Area Code 520
Telephone 571-4000

February 9, 2004

The Honorable Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Citizens Communications Company and UniSource Energy Corporation
Docket No. EC03-54-000

Dear Ms. Salas:

On October 29, 2002, UniSource Energy Corporation (UniSource) entered into an agreement with Citizens Communications Company (Citizens) to acquire Citizens' electric and gas distribution & transmission systems located and operated in the state of Arizona. The Commission approved this transaction in Docket No. EC03-54-000.

Under the structure of the transaction, UniSource has created a wholly-owned subsidiary UniSource Energy Services. Two wholly-owned subsidiaries of UniSource Energy Services were created to own and operate the assets acquired from Citizens. These companies are UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric.)

The following is a summary of the acquisition entries which will clear Account 102, Gas/*Electric plant purchased or sold.*

UNS Gas provides its journal entries on Attachment No. 1 to record the initial capitalization of UNS Gas, the acquisition of Citizens' Arizona gas assets and the clearing of Account 102, *Gas plant purchased or sold.*

UNS Electric provides its journal entries on Attachment No. 2 to record the initial capitalization of UNS Electric, the acquisition of Citizens' Arizona electric assets and the clearing of Account 102, *Electric plant purchased or sold.*

I. SUMMARY OF PROPOSED JOURNAL ENTRIES

A. UNS Gas, Attachment No. 1

Journal Entry No. 1 records the initial capitalization of UNS Gas with sufficient cash to purchase the assets. The capital structure was 33% equity and 67% long-term debt. Journal Entry No. 2 reflects the acquisition of the gas system assets. Journal Entry No. 3 to Account 102, *Gas plant purchased or sold,* records the appropriate plant accounts. Journal Entry No. 4 reflects the clearing of Account 102, *Gas plant purchased or sold,* to Account 114, *Gas plant acquisition adjustments.* Entry No. 5 reflects the reclassification of the remaining balance in Account 114 to Account 108, *Accumulated provision for depreciation of gas utility plant.*

UNS Gas believes its proposed accounting for the clearing of Accounts 102 and 114 is consistent with the Commission's Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act[1] and past accounting decisions.

B. UNS Electric, Attachment No. 2

Journal Entry No. 1 records the initial capitalization of UNS Electric with sufficient cash to purchase the assets. The capital structure was 34% equity and 66% long-term debt. Journal Entry No. 2 reflects the acquisition of the electric system assets. Journal Entry No. 3 to Account 102, *Electric plant purchased or sold,* records the appropriate plant accounts. Journal Entry No. 4 reflects the clearing of Account 102, *Electric plant purchased or sold* to Account 114, *Electric plant acquisition adjustments.* Entry No. 5 reflects the clearing of the remaining balance in Account 114 to Account 108, *Accumulated provision for depreciation of electric utility plant.*

UNS Electric believes its proposed accounting for the clearing of Accounts 102 and 114 is consistent the with the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act[2] and past accounting decisions.

C. Proforma Financial Statements, Attachment No. 3

The effect of the proposed journal entries on the financial statements of UNS Gas and UNS Electric is shown in Attachment 3. The financial statements provided are an August 11, 2003 balance sheet and an income statement for the seven months and eleven days ended August 11, 2003.

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[1] 18 CFR Ch. 1, Part 201
[2] 18 CRF Ch. 1, Part 101

II. SUPPORT FOR PROPOSED JOURNAL ENTRIES

A. Background of Commission Accounting Requirements

The Commission has put into place accounting systems that recognize, measure, and report economic consequences in accordance with the standards that are prescribed for rates. Under the accounting model, the Commission has a longstanding policy of requiring that a jurisdictional utility classify any differences between the purchase price of utility plant acquired in connection with an acquisition and the related original cost of those assets as an acquisition adjustment in Account 114, *Gas/Electric plant acquisition adjustments.* In those cases in which the purchase price is less than the original cost of the related assets, the so-called "negative" acquisition adjustment, the Commission has directed jurisdictional utilities to reclassify the negative amounts to Account 108, *Accumulated provision for depreciation of gas/electric utility plant.*

B. Accounting for the Acquisition Adjustment and the Clearing of Account 102

The proposed entries to Account 102 *Gas plant purchased or sold* for UNS Gas are a debit of $137,186,838 to record the purchase of the gas plant (Entry 2 of Attachment 1), a credit of $206,265,427 to record the plant values (Entry 3 of Attachment 1) and a debit of $69,078,589 to clear Account 102 (Entry 4 of Attachment 1).

The proposed entries to Account 102 *Electric plant purchased or sold* for UNS Electric are a debit of $90,814,602 to record the purchase of the gas plant (Entry 2 of Attachment 2), a credit of $196,379,238 to record the plant values (Entry 3 of Attachment 2) and a debit of $105,564,636 to clear Account 102 (Entry 4 of Attachment 2).

UNS Gas and UNS Electric propose to reclassify the "negative" acquisition adjustments to Account 108 (Entries 5 of Attachment 1 and 2).

As support for this proposed accounting, UNS Gas and UNS Electric rely on the accounting treatment for business combinations under generally accepted accounting principles (GAAP). The Financial Accounting Standards Board (FASB) recently revised the accounting standards for business combinations. The revised standards require that the purchase price of the assets be allocated among the assets based on the fair market value of the assets acquired. The fair market value of the gas and electric system assets acquired is equal to the acquisition price agreed to by the parties. After allocating the acquisition price to those assets carried on the balance sheet at fair market value (e.g., cash, accounts receivable, etc.) the remaining balance reflects the fair market value of the gas and electric plant assets acquired. The reclassification of the "negative" acquisition adjustment to Account 108 results in a book value equal to the fair market value of the assets acquired.

Over the years the Commission has emphasized its overall objective and goal of minimizing the differences between accounting and financial statement presentation in reports prepared for the FERC, stockholders, and others. Therefore, UNS Gas and UNS Electric believe it is appropriate to account for "negative" acquisition adjustments consistent with the revised GAAP for accounting for business combinations. Therefore, UNS Gas and UNS Electric request approval for the reclassification of the "negative" acquisition adjustment to Account 108 and for the clearing of Account 102.

If you require additional information please contact me at (520) 745-3122.

Very truly yours,

Karen G. Kissinger
Vice President, Controller and
Chief Compliance Officer

KGK/gb

Attachment No. 1

UniSource Energy Services
UNS Gas
Journal Entries for the Purchase of Citizens Gas Co. Assets

	FERC Acct	Debit	Credit
1			
Cash	131	150,000,000	
Common Stock Subscribed	202		10
Donations Received from Stockholders	208		49,999,990
Other Long-Term Debt	224		100,000,000
To record the debt and equity transactions for the purchase of the gas assets.			
2			
Gas Plant Purchased	102	137,186,838	
Cash	131		135,792,209
Cash	131		1,503,029
Customer Accounts Receivable	142	1,674,182	
Other Accounts Receivable	143	422,310	
Accumulated Provision for Uncollectible Accounts	144		248,812
Plant Materials and Operating Supplies	154	908,377	
Prepayments	165	353,427	
Accrued Utility Revenues	173	6,366,518	
Miscellaneous Current and Accrued Assets	174	27,422	
Other Regulatory Assets	182.3	383,765	
Unrecovered Purchase Gas Costs	191	5,623,892	
Donations Received from Stockholders	208		1,419,941
Other Long-Term Debt	224		486,820
Accumulated Provisioin for Pension and Benefits	228.3		778,422
Accounts Payable	232		8,613,075
Customer Deposits	235		2,083,759
Interest Accrued	237		61,070
Customer Advances for Construction	252		1,959,594
To record the acquisition of gas plant assets.			
3			
Gas Plant Purchased	102		206,265,427
Gas Plant in Service	101	248,032,644	
Construction Work in Progress - Gas	107	1,408,952	
Accumulated Provision for Depreciation of Gas Utility Plant	108		61,069,331
Accumulated Provision for Amortization and Depletion of Gas Utility Plant	111		378,187
Accumulated Provision for Amortization of Gas Plant Acquisition Adjustment	115		3,045,228
Gas Plant Acquisition Adjustment	114	21,316,577	
To record the original cost of the acquired gas plant assets.			
4			
Gas Plant Purchased	102	69,078,589	
Gas Plant Acquisition Adjustment	114		69,078,589
To close out the balance in account 102, Gas Plant Purchased, to account 114, Gas Plant Acquisition Adjustment.			
5			
Gas Plant Acquisition Adjustment	114	47,762,012	
Accumulated Provision for Depreciation of Gas Utility Plant	108		47,762,012
To reclass negative acquisition adjustment to account 108, Accumulated Provision for Depreciation of Gas Plant.			

Attachment No. 2

UniSource Energy Services
UNS Electric
Journal Entries for the Purchase of Citizens Electric Co. Assets

		FERC Acct	Debit	Credit
1				
	Cash	131	91,000,000	
	Common Stock Subscribed	202		10
	Donations Received from Stockholders	208		30,999,990
	Other Long-Term Debt	224		60,000,000
	To record the debt and equity transactions for the purchase of the electric assets.			
2				
	Electric Plant Purchased or Sold	102	90,814,602	
	Cash	131	7,255	
	Cash	131		82,765,296
	Cash	131		1,002,900
	Other Special Deposits	134	11,340	
	Customer Accounts Receivable	142	6,639,217	
	Other Accounts Receivable	143	63,191	
	Accumulated Provision for Uncollectible Accounts	144		94,524
	Plant Materials and Operating Supplies	154	3,322,561	
	Prepayments	165	229,765	
	Accrued Utility Revenue	173	7,772,812	
	Preliminary Survey & Investigation Charges	183	579,847	
	Donations Received from Stockholders	208		946,627
	Obligations Under Capital Lease -Noncurrent	227		631,806
	Accumulated Provision for Pensions and Benefits	228.3		1,286,578
	Accounts Payable	232		16,320,048
	Customer Deposits	235		2,809,988
	Interest Accrued	237		92,553
	Miscellaneous Current and Accrued Liabilities	242		1,086,785
	Obligations Under Capital Lease -Current	243		74,877
	Customer Advances for Construction	252		1,706,608
	Other Deferred Credits	253		622,000
	To record the acquisition of electric plant assets.			
3				
	Electric Plant Purchased or Sold	102		196,379,238
	Electric Plant in Service	101	307,833,775	
	Property Under Capital Leases	101.1	730,678	
	Construction Work in Progress - Electric	107	8,000,306	
	Accumulated Provision for Depreciation of Electric Utility Plant	108		119,261,742
	Accumulated Provision for Amortization of Electric Utility Plant	111		923,779
	To record the original cost of the acquired electric plant assets.			
4				
	Electric Plant Purchased or Sold	102	105,564,636	
	Electric Plant Acquisition Adjustments	114		105,564,636
	To close out the balance in account 102, Electric Plant Purchased, to account 114, Electric Plant Acquisition Adjustment.			
5				
	Electric Plant Acquisition Adjustments	114	105,564,636	
	Accumulated Provision for Depreciation of Electric Utility Plant	108		105,564,636
	To reclass negative acquisition adjustment to account 108, Accumulated Provision for Depreciation of Electric Plant.			

Attachment No. 3

UniSource Energy Company
UNS Gas
Comparative Balance Sheet
August 11, 2003
(Unaudited)

Title of Account (a)	Balance at Aug. 11, 2003 (b)	Proposed Journal Entries JE No. 1 (c)	JE No. 2 (d)	JE No. 3 (e)	JE No. 4 (f)	JE No. 5 (g)	Proforma Balance (h)
Assets and Other Debits							
Utility Plant							
Gas Plant in Service (101)				248,032,644			248,032,644
Gas Plant Purchased or Sold (102)			137,186,838	(206,265,427)	69,078,589		-
Construction Work in Progress - Gas (107)				1,408,952			1,408,952
Gas Plant Acquisition Adjustment (114)				21,316,577	(69,078,589)	47,762,012	-
Total Fixed Assets	-	-	137,186,838	64,492,746	-	47,762,012	249,441,596
Accumulated Provision for Depreciation of Gas Utility Plant (108,111,115)				(64,492,746)		(47,762,012)	(112,254,758)
Net Utility Plant	-	-	137,186,838	-	-	-	137,186,838
Current Assets							
Cash (131)		150,000,000	(137,295,238)				12,704,762
Customer Accounts Receivable (142)			1,674,182				1,674,182
Other Accounts Receivable (143)			422,310				422,310
Accumulated Provision for Uncollectible Accounts (144)			(248,812)				(248,812)
Plant Materials and Operating Supplies (154)			908,377				908,377
Prepayments (165)			353,427				353,427
Accrued Utility Revenues (173)			6,366,518				6,366,518
Miscellaneous Current and Accrued Assets (174)			27,422				27,422
Total Current Assets	-	150,000,000	(127,791,814)	-	-	-	22,208,186
Deferred Debits							
Other Regulatory Assets (182.3)			383,765				383,765
Unrecovered Purchase Gas Costs (191)			5,623,892				5,623,892
Total Deferred Debits	-	-	6,007,657	-	-	-	6,007,657
Total Assets		150,000,000	15,402,681	-	-	-	165,402,681
Liabilities and Other Debits							
Proprietary Capital							
Common Stock Subcribed (202)		10					10
Donations Received from Stockholders (208)		49,999,990	1,419,941				51,419,931
Total Proprietary Capital	-	50,000,000	1,419,941	-	-	-	51,419,941
Long-Term Debt							
Other Long-Term Debt (224)		100,000,000	486,820				100,486,820
Total Long-Term Debt	-	100,000,000	486,820	-	-	-	100,486,820
Other Noncurrent Liabilities							
Accumulated Provision for Pension and Benefits (228.3)			778,422				778,422
Total Other Noncurrent Liabilities	-	-	778,422	-	-	-	778,422
Current and Accrued Liabilities							
Accounts Payable (232)			8,613,075				8,613,075
Customer Deposits (235)			2,083,759				2,083,759
Interest Accrued (237)			61,070				61,070
Total Current and Accrued Liabilities	-	-	10,757,904	-	-	-	10,757,904
Deferred Credits							
Customer Advances for Construction (252)			1,959,594				1,959,594
Total Deferred Credits	-	-	1,959,594	-	-	-	1,959,594
Total Liabilities and Other Credits		150,000,000	15,402,681	-	-	-	165,402,681

Attachment No. 3 - Continued

UniSource Energy Company
UNS Electric
Comparative Balance Sheet
August 11, 2003
(Unaudited)

Title of Account (a)	Balance at Aug. 11, 2003 (b)	Proposed Journal Entries JE No. 1 (c)	JE No. 2 (d)	JE No. 3 (e)	JE No. 4 (f)	JE No. 5 (g)	Proforma Balance (h)
Assets and Other Debits							
Utility Plant							
Electric Plant in Service (101)				307,833,775			307,833,775
Property Under Capital Lease (101.1)				730,678			730,678
Electric Plant Purchased or Sold (102)			90,814,602	(198,379,238)	105,564,636		-
Construction Work In Progress - Electric (107)				8,000,306			8,000,306
Electric Plant Acquisition Adjustments (114)					(105,564,636)	105,564,636	-
Total Fixed Assets	-	-	90,814,602	120,185,521	-	105,564,636	316,564,759
Accum. Prov. for Depr. of Electric Utility Plant (108,111)				(120,185,521)		(105,564,636)	(225,750,157)
Net Utility Plant	-	-	90,814,602	-	-	-	90,814,602
Current Assets							
Cash (131)		91,000,000	(83,760,941)				7,239,059
Other Special Deposits (134)			11,340				11,340
Customer Accounts Receivable (142)			6,639,217				6,639,217
Other Accounts Receivable (143)			63,191				63,191
Accumulated Provision for Uncollectible Accounts (144)			(94,524)				(94,524)
Plant Materials and Operating Supplies (154)			3,322,561				3,322,561
Prepayments (165)			229,765				229,765
Accrued Utility Revenue (173)			7,772,812				7,772,812
Total Current Assets	-	91,000,000	(65,816,579)	-	-	-	25,183,421
Deferred Debits							
Preliminary Survey & Investigation Charges (183)			579,847				579,847
Total Deferred Debits	-	-	579,847	-	-	-	579,847
Total Assets		91,000,000	25,577,870	-	-	-	116,577,870
Liabilities and Other Credits							
Proprietary Capital							
Common Stock Subscribed (202)		10					10
Donations Received from Stockholders (208)		30,999,990	946,627				31,946,617
Total Proprietary Capital	-	31,000,000	946,627	-	-	-	31,946,627
Long-Term Debt							
Other Long-Term Debt (224)		60,000,000					60,000,000
Total Long-Term Debt	-	60,000,000	-	-	-	-	60,000,000
Other Noncurrent Liabilities							
Obligations Under Capital Lease-Noncurrent (227)			631,806				631,806
Accumulated Provision for Pensions and Benefits (228.3)			1,286,578				1,286,578
Total Other Noncurrent Liabilities	-	-	1,918,384	-	-	-	1,918,384
Current and Accrued Liabilities							
Accounts Payable (232)			16,320,048				16,320,048
Customer Deposits (235)			2,809,988				2,809,988
Interest Accrued (237)			92,553				92,553
Miscellaneous Current and Accrued Liabilities (242)			1,086,785				1,086,785
Obligations Under Capital Lease -Current (243)			74,877				74,877
Total Current and Accrued Liabilities	-	-	20,384,251	-	-	-	20,384,251
Deferred Credits							
Customer Advances for Construction (252)			1,706,608				1,706,608
Other Deferred Credits (253)			622,000				622,000
Total Deferred Credits	-	-	2,328,608	-	-	-	2,328,608
Total Liabilities and Other Credits		91,000,000	25,577,870	-	-	-	116,577,870

Attachment No. 3 - Continued

Unisource Energy Company
UNS Gas
Statement of Income
Year - to - Date
August 11, 2003
(Unaudited)

Title of Account (a)	Year-To-Date Oct. 31, 2002 (b)	Pro Forma Adjustment (c)	Proforma Balance (d)
Utility Operating Income			
Operating Revenues (400)	$ -	$ -	$ -
Operating Expenses			
Operation Expenses (401)	-	-	-
Maintenance Expenses (402)	-	-	-
Depreciation Expense (403)	-	-	-
Taxes Other Than Income Taxes (408)	-	-	-
Income Taxes (409)	-	-	-
Total Operating Expenses	-	-	-
Utility Operating Income	-	-	-
Other Income and Deductions			
Interest and Dividend Income (419)	-	-	-
Investment Tax Credits (420)	-	-	-
Miscellaneous Nonoperating Income (421)	-	-	-
Loss on Disposition of Property (421.9)	-	-	-
Miscellaneous Income Deductions (426)	-	-	-
Total Other Income and Deductions	-	-	-
Interest Charges			
Other Interest Expense (431)	-	-	-
Allowance for Borrowed Funds Used During Construction (432)	-	-	-
Total Interest Charges	-	-	-
Net Income	$ -	$ -	$ -

Note: No pro forma adjustments are reflected because the transaction itself does not impact GasCo. revenues or expenses

Attachment No. 3 - Continued

Unisource Energy Company
UNS Electric
Statement of Income
Year - to - Date
August 11, 2003
(Unaudited)

Title of Account (a)	Year-To-Date Aug. 11, 2003 (b)	Pro Forma Adjustment (c)	Proforma Balance (d)
Utility Operating Income			
Operating Revenues (400)	$ -	$ -	$ -
Operating Expenses			
Operation Expenses (401)	-	-	-
Maintenance Expenses (402)	-	-	-
Depreciation Expense (403)	-	-	-
Taxes Other Than Income Taxes (408)	-	-	-
Income Taxes (409)	-	-	-
Total Operating Expenses	-	-	-
Utility Operating Income	-	-	-
Other Income and Deductions			
Interest and Dividend Income (419)	-	-	-
Investment Tax Credits (420)	-	-	-
Miscellaneous Nonoperating Income (421)	-	-	-
Loss on Disposition of Property (421.9)	-	-	-
Miscellaneous Income Deductions (426)	-	-	-
Total Other Income and Deductions	-	-	-
Interest Charges			
Other Interest Expense (431)	-	-	-
Allowance for Borrowed Funds Used During Construction (432)	-	-	-
Total Interest Charges	-	-	-
Net Income	$ -	$ -	$ -

Note: No pro forma adjustments are reflected because the transaction itself does not impact UNS Electric revenues or expenses

EXHIBIT

KGK-6

EXECUTIVE SUMMARY-RONALD E. WHITE

Dr. White conducted depreciation studies for Citizens Communications Company's Northern Arizona Gas Division ("NAGD") and Santa Cruz Gas Division ("SCGD"). Dr. White collected plant accounting data from the Company, visited the Arizona properties to examine the plant, and engaged in discussions with several Company personnel. Relying on this information, Dr. White used accepted depreciation procedures and his expert judgment based on years of experience to develop revised depreciation rates for both the NAGD and the SCGD.

For both properties, Dr. White is proposing composite depreciation rates that are significantly below the current rates. The proposed composite rate for NAGD is 2.72%, compared with a current composite rate of 3.51%. Similarly, the proposed composite rate for SCGD is 1.97%, compared with the current composite rate of 3.69%. In both properties, this reduced rate in part results from the fact that Citizens has expended substantial sums for new plant (such as distribution and transmission facilities), as well as for maintaining and reinforcing existing plant. Company witness Doherty has used Dr. White's proposed depreciation rates to calculate proposed depreciation expenses, which are also significantly lower than current depreciation expenses.

EXHIBIT

KGK-7

CITIZENS COMMUNICATIONS CO - Northern Arizona Gas Division
Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Future Salvage	Accrual Rate	Rem. Life	Future Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
TRANSMISSION							
367.00 Mains	22.50		2.57%	55.32	-10.0%	22.30%	1.59%
369.00 Measuring and Regulating Station Equip.	19.00	-5.0%	3.32%	49.42	-5.0%	25.57%	1.61%
Total Transmission			2.63%	54.70	-9.6%	22.55%	1.59%
DISTRIBUTION							
376.00 Mains	29.10	-10.0%	2.22%	47.62	-20.0%	19.31%	2.11%
378.00 Measuring and Regulating Equipment	17.70	-30.0%	5.73%	35.82	-30.0%	19.68%	3.08%
379.00 Measuring and Regulating Station Equip,	13.80		5.52%	35.67		14.88%	2.39%
380.00 Services	34.80	-130.0%	4.75%	44.07	-50.0%	23.32%	2.87%
381.00 Meters	26.90		2.86%	26.84		44.44%	2.07%
382.00 Meter Installations	26.90		2.86%	36.42		10.87%	2.45%
383.00 House Regulators	20.20		3.77%	27.99		24.33%	2.70%
384.00 House Regulator Installations	20.20		3.77%	33.41		5.52%	2.83%
385.00 Industrial Meas. And Reg. Station Equip.	22.70	-40.0%	3.82%	29.21	-40.0%	63.88%	2.61%
387.00 Other Equipment	19.90		3.64%	23.54		26.41%	3.13%
Total Distribution			2.99%	44.80	-25.9%	21.49%	2.33%
GENERAL PLANT							
390.00 Structures and Improvements	10.80		3.10%	22.39		16.18%	3.74%
391.00 Office Furniture and Equipment	14.20		4.82%	19.07		18.90%	4.25%
391.10 Office Furniture and Equip. - Computers	4.80		20.00%	2.64		63.26%	13.92%
391.20 Office Furniture and Equip. - Mechanical	14.20		4.54%	21.37		3.64%	4.51%
393.00 Stores Equipment	22.30		2.27%	30.76		6.72%	3.03%
394.00 Tools, Shop & Garage Equipment	15.30		5.76%	19.76		28.82%	3.60%
395.00 Laboratory Equipment	15.30		5.76%	5.65		46.68%	9.44%
396.00 Power Operated Equipment	6.80	10.0%	24.60%	8.19	10.0%	38.59%	6.28%
397.00 Communication Equipment	7.70		4.93%	11.74		28.98%	6.05%
398.00 Miscellaneous Equipment	7.00		5.43%	22.10		11.49%	4.01%
Total General Plant			9.55%	9.16	0.2%	31.95%	7.41%
CONTRIBUTIONS IN AID OF CONSTRUCTION							
376.09 Mains	29.10	-10.0%	2.22%	33.41		48.73%	1.53%
380.09 Services	34.80	-130.0%	4.75%	46.18		9.30%	1.96%
Total Contributions in Aid of Construction			2.63%	36.06		42.30%	1.60%
TOTAL UTILITY			3.51%	37.62	-24.0%	21.57%	2.72%

CITIZENS COMMUNICATIONS CO - Santa Cruz Gas Division

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Future Salvage	Accrual Rate	Rem. Life	Future Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
TRANSMISSION							
367.00 Mains		-5.0%	2.67%	36.86	-10.0%	79.82%	0.82%
369.00 Measuring and Regulating Equipment			4.14%	43.56	-5.0%	47.84%	1.31%
Total Transmission			2.73%	37.23	-9.8%	78.57%	0.84%
DISTRIBUTION							
375.00 Structures and Improvements			7.27%	16.64		79.21%	1.25%
376.00 Mains		-5.0%	2.99%	43.64	-20.0%	48.93%	1.63%
378.00 Meas. and Reg. Sta. Equip. - General			3.07%	31.66		38.64%	1.94%
379.00 Meas. and Reg. Sta. Equip. - City Gate			3.07%	33.75		26.38%	2.18%
380.00 Services		-25.0%	5.65%	39.69	-50.0%	47.85%	2.57%
381.00 Meters			2.58%	26.51		50.83%	1.85%
382.00 Meter Installations			2.58%	29.96		38.64%	2.05%
383.00 House Regulators			4.06%	22.87		52.16%	2.09%
384.00 House Regulator Installations			4.06%	34.50		2.14%	2.84%
Total Distribution			3.71%	39.74	-25.4%	48.50%	1.93%
GENERAL PLANT							
390.00 Structures and Improvements			3.50%	21.56		14.46%	3.97%
391.00 Office Furniture and Equipment			3.94%	25.00		15.67%	3.37%
394.00 Tools, Shop & Garage Equipment			3.39%	21.60		13.33%	4.01%
395.00 Laboratory Equipment			3.28%	16.41		42.84%	3.48%
396.00 Power Operated Equipment			0.99%	11.67	10.0%	57.20%	2.81%
397.00 Communication Equipment			4.13%	13.52		9.28%	6.71%
398.00 Miscellaneous Equipment			5.06%	20.51		17.16%	4.04%
Total General Plant			3.33%	20.35	0.6%	17.90%	4.00%
CONTRIBUTIONS IN AID OF CONSTRUCTION							
376.09 Mains		-5.0%	2.99%	50.95		22.56%	1.52%
380.09 Services		-25.0%	5.65%	44.67		16.02%	1.88%
Total Contributions in Aid of Construction			3.27%	50.14		21.86%	1.56%
TOTAL UTILITY			3.69%	38.45	-25.3%	49.45%	1.97%

EXHIBIT

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average level of account write-offs, net of subsequent recoveries, experienced during the past three years. Since the portion of customer bills for the base cost of gas and the PGA are subject to write-off, such amounts have been added to the computational base.

The portion of Adjustment C relating to interest on customer deposits is related to the deduction of customer deposits from rate base, discussed in connection with Schedule B-9. It reflects the fact that such interest is typically recorded as a component of Other Interest Expense, which would not afford the Company the opportunity to recover such costs through the ratemaking process, absent this reclassification to operating expenses. The adjustment was computed based on the end-of-year balance of customer deposits and the prescribed rate of 6%.

Q. Please discuss Adjustment I, relating to Depreciation Expense.

A. Adjustment I in Schedule C-2 sets forth, by prime account, the AGD's adjusted depreciation expense for the test year using the adjusted plant balance as of December 31, 2001, and the depreciation rates proposed by Dr. White. These factors result in a significant decrease to the AGD's depreciation expense.

Q. Please describe the next operating expense item, relating to Lease Expense for New Office Facilities.

A. As noted above, subsequent to the test year, the AGD personnel relocated from the administrative office building located on Yale Street in Flagstaff, to a leased facility. This was a part of a cost-cutting approach adopted by AGD. Pro forma Adjustment J reflects the annual lease expense that is a

EXHIBIT

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CITIZENS COMMUNICATIONS COMPANY
ARIZONA GAS DIVISION--COMBINED

INCOME STATEMENT AND PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2001

Line #	Description	[1] Factor Or Reference	[2] A Revenues AGD	[3] B Salaries & Wages AGD	[4] C Uncollectibles & Int on Cust. Dep AGD	[5] D Reg/Misc. Per Diem AGD	[6] E Insurance AGD	[7] F Injuries & Damages AGD	[8] G Pension & Benefits AGD	[9] H Taxes Other Than Income AGD	[10] I Depreciation & Amort. AGD	[11] J Lease Admin Bldg NAGD	[12] SUB-TOTAL Adjusiments
	REVENUE												
1	Residential		$ (28,124,310)										$ (28,124,310)
2	Commercial		(13,214,537)										(13,214,537)
3	Industrial		(1,475,256)										(1,475,256)
4	Irrigation		(91,618)										(91,618)
5	Public Authority		(2,288,831)										(2,288,831)
6	Forfeited Discounts												-
7	Misc. Service Revenues												-
8	Other Revenue												-
9	Transportation		46,914										46,914
10	Other		-										-
11	Cost of Gas		-										-
12	Revenue Increase To Be Spread												-
13	TOTAL REVENUE		(45,147,638)	-	-	-	-	-	-	-	-	-	(45,147,638)
	OPERATING REVENUE DEDUCTIONS												
	Operations and Maintenance												
14	---Purchased Commodities		(44,937,283)										(44,937,283)
15	---Other Production			(289)									(289)
16	---Transmission and Distribution			746									746
17	---Customer Accounting and Collecting			5,654	(444,069)								(438,415)
18	---Sales Promotion			-									-
19	---Administrative and General			(2,004)		165,196	11,255	54,158	369,753			486,000	1,084,358
20	---Other												-
21	Total O & M Expenses		(44,937,283)	4,107	(444,069)	165,196	11,255	54,158	369,753	-	-	486,000	(44,290,883)
22	Depreciation and Amortization										(2,005,664)		(2,005,664)
23	Non-Plant Amortization												-
24	Taxes-Other Than Income									96,279			96,279
25	OPERATING EXPENSES		(44,937,283)	4,107	(444,069)	165,196	11,255	54,158	369,753	96,279	(2,005,664)	486,000	(46,200,268)
26	OPERATING INCOME BEFORE TAXES		(210,355)	(4,107)	444,069	(165,196)	(11,255)	(54,158)	(369,753)	(96,279)	2,005,664	(486,000)	1,052,630
27	Taxes on Income (Adjustment S)	39.530%	(83,153)	(1,623)	175,540	(65,302)	(4,449)	(21,409)	(146,163)	(38,059)	792,839	(192,116)	416,105
28	OPERATING INCOME	L 22 - L 23	$ (127,202)	$ (2,484)	$ 268,529	$ (99,894)	$ (6,806)	$ (32,749)	$ (223,590)	$ (58,220)	$ 1,212,825	$ (293,884)	$ 636,525

AGD Combined RCM 7-13 xls
Sec ClSch_C_2_P1 (X1..AY60)

Exhibit KGK – 9
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CITIZENS COMMUNICATIONS COMPANY
ARIZONA GAS DIVISION–COMBINED

INCOME STATEMENT AND PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2001

Line #	Description	[1] Factor Or Reference	[2] SUB-TOTAL Adjustments	[3] K Prior Period Taxes NAGD	[4] L Administrative Office Exp. AGD	[5] M Amortization Gain on Sale NAGD	[6] N Supply Line Maintenance SCGD	[7] O Y2K Amortization AGD	[8] P Postage Expense AGD	[9] Q CARES Expenses AGD	[10] R NAGD P/R Chgs to SCGD AGD	[11] S Income Tax Adjustment AGD	[12] TOTAL Adjustments
	REVENUE												
1	Residential		$ (28,124,310)										$ (28,124,310)
2	Commercial		(13,214,537)										(13,214,537)
3	Industrial		(1,475,256)										(1,475,256)
4	Irrigation		(91,618)										(91,618)
5	Public Authority		(2,288,831)										(2,288,831)
6	Forfeited Discounts		-										-
7	Misc. Service Revenues		-										-
8	Other Revenue		-										-
9	Transportation		46,914										46,914
10	Other		-										-
11	Cost of Gas		-										-
12	Revenue Increase To Be Spread												-
13	TOTAL REVENUE		(45,147,638)	-	-	-	-	-	-	-	-	-	(45,147,638)
	OPERATING REVENUE DEDUCTIONS												
	Operations and Maintenance												
14	---Purchased Commodities		(44,937,283)										(44,937,283)
15	---Other Production		(289)										(289)
16	---Transmission and Distribution		746				5,000						5,746
17	---Customer Accounting and Collecting		(438,415)						39,756	217,913			(180,746)
18	---Sales Promotion		-										-
19	---Administrative and General		1,084,358		(152,103)						(428)		931,827
20	---Other		-										-
21	Total O & M Expenses		(44,290,883)	-	(152,103)	-	5,000	-	39,756	217,913	(428)	-	(44,180,745)
22	Depreciation and Amortization		(2,005,664)										(2,005,664)
23	Non Plant Amortization		-			(20,886)		76,753					55,867
24	Taxes-Other Than Income		96,279	1,213,112									1,309,391
25	OPERATING EXPENSES		(46,200,268)	1,213,112	(152,103)	(20,886)	5,000	76,753	39,756	217,913	(428)	-	(44,821,151)
26	OPERATING INCOME BEFORE TAXES		1,052,630	(1,213,112)	152,103	20,886	(5,000)	(76,753)	(39,756)	(217,913)	428	-	(326,487)
27	Taxes on Income (Adjustment S)	39.530%	416,105	(479,543)	60,126	8,256	(1,977)	(30,340)	(15,716)	(86,141)	169	3	(129,058)
28	OPERATING INCOME		$ 636,525	$ (733,569)	$ 91,977	$ 12,630	$ (3,023)	$ (46,413)	$ (24,040)	$ (131,772)	$ 259	$ (3)	$ (197,429)

EXHIBIT

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CITIZENS COMMUNICATIONS COMPANY
ARIZONA GAS DIVISION—COMBINED

INCOME STATEMENT
TEST YEAR ENDED DECEMBER 31, 2001

SECTION C
SCHEDULE C-1
Page 1 of 1
WITNESS Doherty

Line #	Description	[1] Reference	[2] Recorded Amounts (Excl Griffith)	[3] Non Jurisdictional Adjustments	[4] Recorded Jurisdictional Amounts [2]+[3]	[5] Pro Forma Adjustments	[6] Pro Forma At Present Rates [4]+[5]	[7] Proposed Revenue Change	[8] Pro Forma At Proposed Rates [6]+[7]
	REVENUE								
1	Residential		$ 47,410,869		$ 47,410,869	$ (28,124,310)	$ 19,286,559		$ 19,286,559
2	Commercial		17,921,764		17,921,764	(13,214,537)	4,707,227		4,707,227
3	Industrial		1,773,689		1,773,689	(1,475,256)	298,433		298,433
4	Irrigation		103,015		103,015	(91,618)	11,397		11,397
5	Public Authority		3,332,962		3,332,962	(2,288,831)	1,044,131		1,044,131
6	Forfeited Discounts		286,045		286,045		286,045		286,045
7	Misc. Service Revenues		541,428		541,428		541,428		541,428
8	Other Revenue		15,313		15,313		15,313		15,313
9	Transportation		1,225,520		1,225,520	46,914	1,272,434		1,272,434
10	Other		-		-	-	-		-
11	Cost of Gas		-		-	-	-		-
12	Revenue Increase To Be Spread				-		-	21,005,522	21,005,522
13	TOTAL REVENUE		72,610,605	-	72,610,605	(45,147,638)	27,462,967	21,005,522	48,468,489
	OPERATING REVENUE DEDUCTIONS								
	Operations and Maintenance								
14	---Purchased Commodities		44,937,283		44,937,283	(44,937,283)	-		-
15	---Other Production		732,644		732,644	(289)	732,355		732,355
16	---Transmission and Distribution		5,096,497		5,096,497	5,746	5,102,243		5,102,243
17	---Customer Accounting and Collecting		5,768,943		5,768,943	(180,746)	5,588,197	24,733	5,612,930
18	---Sales Promotion		15,184		15,184	-	15,184		15,184
19	---Administrative and General		6,586,723		6,586,723	931,827	7,518,550		7,518,550
20	---Other Expenses		-		-	-	-		-
21	Total O & M Expenses		63,137,274	-	63,137,274	(44,180,745)	18,956,529	24,733	18,981,262
22	Depreciation and Amortization		8,085,696		8,085,696	(2,005,664)	6,080,032		6,080,032
23	Non-Plant Amortization		-		-	55,867	55,867		55,867
24	Taxes-Other Than Income		3,433,032		3,433,032	1,309,391	4,742,423		4,742,423
25	OPERATING EXPENSES		74,656,002	-	74,656,002	(44,821,151)	29,834,851	24,733	29,859,584
26	OPERATING INCOME BEFORE TAXES		(2,045,397)	-	(2,045,397)	(326,487)	(2,371,884)	20,980,789	18,608,905
27	Taxes on Income		(2,797,681)		(2,797,681)	(129,058)	(2,926,739)	8,289,808	5,363,069
28	OPERATING INCOME		$ 752,284	$ -	$ 752,284	$ (197,429)	$ 554,855	$ 12,690,981	$ 13,245,836

AGD Combined RCM 7-13.xls
Sec CISch_C_1 (A1..T60)

EXHIBIT

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Appendix B - Schedule 1

UniSource Acquisition of Citizens Utility
2001 Test Year

Line No.	Description	Citizens Original Cost Rate Base	UniSource As Filed	UniSource Settlement
1	Gross Utility Plant in Service (w/CIAC)	$219,383,559	$219,383,559	$219,383,559
2	Accumulated Depreciation	($53,751,970)	($53,751,970)	($53,751,970)
3	Adjustment for Purchase		($30,709,737)	($30,709,737)
4	Adjustment to the Build Out Program			($10,000,000)
5	Net Utility Plant in Service	$165,631,589	$134,921,852	$124,921,852
6	Accumulated Deferred Income Taxes	($5,713,762)		
7	Advances for Construction	($6,395,371)	($6,395,371)	($6,395,371)
8	Customer Deposits	($1,812,850)	($1,812,850)	($1,812,850)
9	Materials and Supplies	$968,581	$968,581	$968,581
10	Warm Spirit	($40,001)	($40,001)	($40,001)
11	Cares	($364,946)	($364,946)	($364,946)
12	Sale of Office Buildings	($104,431)		
13	Y2K Costs	$383,765	$383,765	$383,765
14	Allowance for Working Capital	($2,924,219)		
	Total Rate Base	$149,628,355	$127,661,030	$117,661,030
16	Total Return	$13,242,109	$11,553,323	$10,648,323
17	Operating Expenses	$29,859,583	$28,883,183	$28,883,183
18	Income Taxes	$5,426,078	$3,703,569	$3,413,459
19	Proposed Revenue	$48,531,496	$44,140,075	$42,944,966
20	Proposed (Required) Operating Income	$13,245,835	$11,553,323	$10,648,323
20	Current Operating Income	$554,855	$1,499,758	$1,499,758
21	Proposed Increase in Operating Income	$12,687,254	$10,053,565	$9,148,565
22	Gross Revenue Conversion Factor	1.656	1.656	1.656
23	Increase in Gross Revenue	$21,005,521	$16,645,370	$15,146,990
24	Depreciation Adjustment for Build Out Reduction			($272,000)
25	Reversal of Taxes on Debt for Build Out Reduction			$304,886
26	Adjustment for Difference Regarding Debt for Build Out Reduction			$11,400
27	Increase in Gross Revenue with all Build Out Adjustme	$21,005,521	$16,645,370	$15,191,276
28	Test Year Gross Revenue	$72,610,605	$72,610,605	$72,610,605
29	Percent Increase over Present Rates	28.93%	22.92%	20.92%

UniSource's Cost of Capital-Settlement

	Cost	Weight	WACC
Debt	7.75%	60.00%	4.65%
Equity	11.00%	40.00%	4.40%
			9.05%

Citizen's Cost of Capital

	Cost	Weight	WACC
Debt	6.70%	50.00%	3.35%
Equity	11.00%	50.00%	5.50%
			8.85%

UNS Filed Equity Return	Settlement Equity Return
$5,617,085	$5,177,085

EXHIBIT

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years on the New Contract for purchased power, the customers acquired by UniSource will enjoy relative rate stability in base rates and purchased power rates[7] for at least the next several years. We find that the base rate moratorium provision provides a significant benefit to affected ratepayers. However, we believe the Settlement Agreement should be modified slightly to make it clear that GasCo and ElecCo shall not be permitted to increase their gas or electric base rates prior to August 1, 2007.

I. Terms of Gas Rate Case Agreement

The Signatory Parties agree that, for ratemaking purposes, the Fair Value Rate Base ("FVRB") for the Citizens' gas assets to be acquired by GasCo is $142,132,013, as of October 29, 2002 (See Appendix B, Schedule 2, of Settlement Agreement). The Signatory Parties further agree that, for ratemaking purposes, a reasonable rate of return on the stipulated FVRB equals 7.49 percent. The stipulated rate of return is based on a total cost of capital of 9.05 percent, derived from a cost of equity of 11.00 percent and a cost of debt of 7.75 percent for original cost rate base (See Appendix B, Schedule 1, of Settlement Agreement). The Settlement provides that GasCo's increase in revenues will equal $15,191,276 (See Appendix B, Schedule 1, of Settlement Agreement). The Agreement also sets forth a rate design for the new gas rates that includes, among other things, that the monthly customer charge will increase from $5.00 to $7.00 and the base cost of gas implicit in the commodity rates for all tariff classes will be $0.400 per therm (See Appendix B, Schedule 3, of Settlement Agreement).

The Signatory Parties further agree that the purchased gas adjustor ("PGA") bank balance will not be affected by the Agreement and that UniSource and/or GasCo will comply with all prior Commission orders regarding treatment of the PGA bank balance. With respect to the new stipulated $0.400 per therm base cost of gas, the Settlement provides that the existing $0.100 per therm (over 12 months) fluctuation limit, without Commission approval, shall be increased to $0.150 for 12 consecutive months after approval of the Settlement. At the end of that period, the PGA rate would revert to the current $0.100 per therm fluctuation limit.

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[7] Purchased power rates could be reduced during this period if UniSource is successful in renegotiating the New Contract with PWCC.

IT IS FURTHER ORDERED that UniSource is authorized to create subsidiaries to own and operate the electric and gas utility assets purchased from Citizens and, if necessary, to form an intermediate holding company to finance and own the electric and gas subsidiaries.

IT IS FURTHER ORDERED that, pursuant to A.R.S. §§40-301 *et seq.*, the proposed financing arrangements are approved, including bridge financing, bond financing, and revolving credit financing by UniSource's electric and gas subsidiaries, and the issuance of stock by those companies.

IT IS FURTHER ORDERED that, pursuant to A.A.C. R14-2-804, TEP is authorized to loan up to $50 million to UniSource for the sole purpose of funding the purchase of Citizens' gas and electric business, subject to the terms and conditions set forth in the Settlement Agreement.

IT IS FURTHER ORDERED that, pursuant to A.A.C. R14-2-803, UniSource is authorized to capitalize the new electric and gas subsidiaries, subject to the terms of the Settlement Agreement.

IT IS FURTHER ORDERED that, pursuant to the terms of the Settlement Agreement, a waiver shall be granted to Decision No. 60480, as amended by Decision No. 62103, which requires UniSource to invest at least 30 percent of the proceeds of a public stock issuance in TEP. This waiver is granted for the sole purpose of allowing UniSource the ability to finance the acquisition of Citizens' gas and electric assets under the terms of the Settlement.

IT IS FURTHER ORDERED that the fair value rate base of $142,132,013 and rate of return of 7.49 percent are reasonable for the gas operations of Citizens that are to be acquired by UniSource pursuant to the terms of the Settlement Agreement.

IT IS FURTHER ORDERED that the stipulated increase in gas operation revenues in accordance with the Settlement Agreement, including the stipulated rate design and tariff modifications related to service line and main extension policies, are approved.

IT IS FURTHER ORDERED that UniSource's proposed operating company subsidiaries, ElecCo and GasCo, shall not file a general rate case increase for a period of at least three years from the effective date of this Decision and the rate increase resulting from this general rate increase application shall not become effective prior to August 1, 2007, subject to the exceptions set forth in the Settlement Agreement.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

Gary A. Smith

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Gary A. Smith. My business address is 2901 West Shamrell Blvd., Suite 110 Flagstaff, Arizona 86001.

Q. Are you the same Gary A. Smith that filed Direct Testimony in this case?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Testimony is to respond to certain aspects of the Direct Testimonies filed by Ms. Julie McNeely-Kirwan and Mr. Ralph Smith on behalf of Commission Staff, Ms. Marylee Diaz Cortez on behalf of the Residential Utility Consumers Office ("RUCO"), and Ms. Miquelle Scheier on behalf of the Arizona Community Action Association ("ACAA").

Q. Please summarize your Rebuttal Testimony.

A. With regards to Staff witnesses Julie McNeely-Kirwan and Ralph Smith, the Company agrees with their recommendations on the Warm Spirit program and the modifications to the Company's Rules and Regulations. I, however, do not agree with RUCO witness Marylee Diaz Cortez's criticism of one of the Company's proposed modifications to its Rules and Regulations and I also disagree with the two operating income adjustments made by RUCO witness Rodney Moore. I also will make some comments in response to Ms. Scheier's Direct Testimony.

II. RESPONSE TO STAFF WITNESS JULIE MCNEELY-KIRWAN.

Q. Mr. Smith, have you had an opportunity to review Ms. McNeely-Kirwan's Direct Testimony?

A. Yes, I have. Ms. Denise Smith will respond to Ms. McNeely-Kirwan's comments on Demand Side Management ("DSM") and Mr. D. Bentley Erdwurm will respond to her comments on rate design and customer charges for the Company. I would like to briefly comment on one aspect of her Direct Testimony regarding the Customer Assistance Residential Energy Support ("CARES") expansion and her recommendation about the Warm Spirit program.

Q. Please respond to Ms. McNeely-Kirwan's recommendation with regard to CARES expansion.

A. In her Direct Testimony on page 2, lines 23-25, Ms. McNeely-Kirwan states that "Staff recognizes the improvement and recommends that UNS continue to work toward expanding participation in the CARES program to additional eligible households." UNS Gas agrees with Ms. McNeely-Kirwan about the importance of this program. We strive to add households by distributing CARES applications to local assistance agencies, public libraries, and town and city halls within our service territory. We also insert CARES applications in all residential customers' bills every calendar quarter, (beginning in February of every year). As customers have discussions with the Customer Call Center and indicate difficulty in making payments on their accounts, we provide them the information about and/or an application for the CARES program.

Q. Also in her Direct Testimony, Ms. McNeely-Kirwan recommends – on page 8, lines 6-13 and page 13, lines 20-24 – that the $21,600 in emergency bill assistance proposed by UNS Gas as part of the Low Income Weatherization ("LIW") program be moved into the Warm Spirit program and recovered through base rates. Do you have any response?

A. UNS Gas is amenable to Ms. McNeely-Kirwan's recommendation as long as the Company may recover the funds for the emergency bill assistance through base rates. I am aware that Mr. Ralph Smith made that adjustment for Staff and so the Company agrees to put that money into the Warm Spirit program.

III. <u>RESPONSE TO STAFF WITNESS RALPH SMITH</u>.

Q. Have you had an opportunity to review Staff Witness Ralph Smith's Direct Testimony in this case?

A. Yes, I have. Again, while other UNS Gas witnesses will respond to the majority of the issues raised by Mr. Smith, I would like to briefly comment on his Direct Testimony concerning the Company's Rules and Regulations modifications.

Q. Do the Staff and the Company agree on the Company's modifications to the Rules and Regulations?

A. Yes. Staff supports the modifications we have proposed to our Rules and Regulations.

Q. Does Mr. Smith make any recommendations with regard to implementation of those Rules and Regulations?

A. Yes. On pages 68 and 70 of his Direct Testimony, Mr. Smith recommends that we implement a six-month waiver of the change in the late payment penalty period and the period that customers have to respond to a termination of service notice. The Company is willing to implement such a waiver period and will not operate under the new Rules and Regulations with regard to the late payment penalty period and the period following a termination of service notice for six months.

IV. <u>RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ</u>.

Q. Mr. Smith, on pages 35 to 36 in her Direct Testimony, RUCO Witness Marylee Diaz Cortez takes issue with the Company's proposed change to its Rules and Regulations that would shorten the time customers have to pay their gas bills to avoid late fees or disconnection notices. Do you have any response?

A. Yes. Ms. Diaz Cortez states that the changes are unreasonable and a customer on vacation could come home to find his gas shut-off. Further, she argues that, because UNS Gas receives a working capital allowance, it should not impose the payment terms on customers. Not only is this rationale irrelevant, review of the billing timeline shows that the proposed changes allow for adequate time for customers to pay their bills. Customers receive bills approximately two days after a billing period ends. A customer has 10 days to pay before a bill is considered late. Under the proposed changes, after that 10 day period, a customer has another 15 days before a late fee is assessed, for a total of 25 days since the bill was received. Only then would a bill be considered delinquent. Even so, under Subsection 10.C.4. of the Company's proposed Rules and Regulations, the Company would not commence suspension of service procedures unless it did not receive payment for a delinquent bill after five days. So, the customer has a total of 30 days after a bill receipt to pay his or her bill before a notice of shut-off is issued. After that notice is issued, a customer could have several days before gas is actually disconnected. In addition, if a customer presented good cause to the Company for late payment, the Company has the ability to waive the late fee. Finally, as recognized by Commission witness Ralph Smith, the proposal by the Company is consistent with the specifications of the Arizona Administrative Code, R14-2-310.C. Thus, the time periods proposed by the Company are entirely reasonable.

V. RESPONSE TO RUCO WITNESS RODNEY MOORE.

Q. Have you had an opportunity to review RUCO witness Mr. Rodney Moore's Operating Income Adjustment Nos. 6 and 10?

A. Yes. Review of the proposed disallowances reveals that most are directly related to safety, system integrity and operator training; thus, the expenses are clearly both appropriate and necessary.

Most of the recommended amounts for disallowance refer to expenses incurred performing regulatory-mandated functions such as leak surveys, safety audits, and training. More specifically, annual and cycle leak surveys require teams to be on the road, sometimes for substantial periods of time leak surveying all locations. To best ensure the pipeline integrity and maintain a better-than-industry-average lost and unaccounted for rate, we also perform leak surveys on the residential sections of our distribution system every four years. Mr. Moore's proposed disallowances also include expenses for the preparation and participation in the annual-mandated Commission pipeline safety audit and required operator qualification training, welder qualification training, and emergency response testing. Regulatory mandated requirements dictate that every employee attend at least two modules and up to 19 modules of training, depending on their job classification and duties. For example, to maintain welder qualification, employees must attend classroom and hands-on training every six months. Additionally, every employee, including Call Center personnel, must attend Emergency Response training every year. I must complete two modules of training every year.

RUCO also proposes disallowance of $12,000 spent on communications in support of all our field communication equipment, and for lease of radio towers that are not only used for normal operations and maintenance but for public emergency situations as well, $12,000 for materials, small tools, or personnel protective equipment, and $4,800 for material related to our Circle of Safety employee awareness program. The Circle of Safety program, in addition to promoting safe parking practices, utilizes external cues (*i.e.*, door magnets and safety cones) to remind employees to "circle" their vehicles before leaving a parking spot. By heightening the awareness of the vehicles' surroundings, the goal of the program is to eliminate accidents involving hidden or difficult-to-see obstacles that employees frequently encounter on the job. The costs of this on-going program represent a fraction of the potential savings from the liability and vehicular damage costs avoided from eliminating accidents of this nature. A significant amount of the balance is spent for small tools that are necessary for maintaining the pipeline system.

Thus, the funds proposed for disallowance by Mr. Moore are directly related to the support of system integrity, safety, and operator training and are properly included.

VI. RESPONSE TO ACAA WITNESS MIQUELLE SCHEIER.

Q. Before you respond to Ms. Scheier's specific recommendations, do you have any general comments to make with regard to her Direct Testimony?

A. Yes. UNS Gas understands Ms. Scheier's concerns and is sympathetic to the stresses rising utility bills place on low-income customers. As always, the Company is ready and willing to meet with Ms. Scheier to determine how it can help with those stresses. However, the Company has experienced increased costs that it must cover in order to provide safe and reliable service. The customers from whom those costs are recovered ultimately is a policy question for this Commission. The Company has made some recommendations as to how it would distribute the rising costs, and has tried to maintain appropriate allowances for our low income customers. If this Commission determines that there is a better way in which to distribute the cost increase while retaining the Company's opportunity for full recovery of all prudently incurred expenses in delivering safe and reliable gas service to all customers, the Company will certainly abide by that decision.

Q. Turning to Ms. Scheier's first recommendation on pages 2 and 10 to 11 of her Direct Testimony – that the Commission hold low-income customers harmless by increasing the R12 discount to an amount commensurate with any residential rate increase and reject the Company's proposed structure for R12 – do you have any response?

A. The Commission can make a policy decision as to how it would prefer to spread any rate increase. However, consistent with Mr. Erdwurm's Rebuttal Testimony, the appropriate rate design should channel fixed costs into a fixed customer service charge and variable fuel charges into a per therm charge. The Company incurs fixed costs regardless of consumption. If consumption is reduced, then the Company will not recover the fixed costs expended to serve customers. The Company incurs those fixed costs even when those customers opt to not use gas.

Q. Do you have any response to Ms. Scheier's recommendation on pages 2 and 10 in her Direct Testimony that the Commission increase the marketing of the low-income programs, including the funding effort by Community Action Agencies ("CAA") to reach target low-income customers?

A. Again, the Commission can help the Company decide how to best allocate the dollars to these programs. Of course, as funding for marketing is increased, funding for weatherization and other low income assistance is decreased, assuming a fixed program amount.

Q. On page 2 in her Direct Testimony, Ms. Scheier recommends that the Commission require the automatic enrollment of Low Income Home Energy Assistance Program ("LIHEAP") eligible customers of record in the R12 discount rate program. Do you have any response to this recommendation?

A. While I am not clear if the recommendation is for the automatic enrollment of LIHEAP recipients or simply LIHEAP eligible customers, the Company is happy to enroll LIHEAP recipients who are also current UNS Gas customers of record in the R12 discount rate program. UNS Gas will work with ACAA in order to figure out how to best accomplish the sharing of LIHEAP customer information with the Company.

Q. Ms. Scheier raises concern over the referring of cash-paying customers to "predatory lenders" and the practice of charging additional fees for these customers on page 2 and pages 12-13 of her Direct Testimony. Do you have any response?

A. When UNS Gas closed some of its branch offices to save money for all ratepayers, we were very concerned about providing sufficient and convenient locations for our cash-paying customers. When ACAA first raised its concerns to us in November of 2006, I looked into each of its complaints.

First, on page 12, Ms. Scheier states that UNS Gas, in some instances, charges an additional fee for those customers paying their bills in cash. This is not accurate. In fact, UNS Gas pays any additional fee charged by payment locations as long as the customer does not have the option of paying at a nearby UNS Gas facility. If customers choose to visit a payment center, despite having the choice of paying at an UNS Gas office, then they will pay an additional charge. In all other areas, UNS Gas picks up the additional charge. The bill insert, attached hereto as Exhibit GAS-3, was sent to customers last year in anticipation of the lobby closures and clearly outlines each location's payment options, including use of various cash-payment vendors and courtesy drop boxes for checks and money orders—both of which are available without a fee in these locations. As discussed above, locations where lobbies remained open are listed on our website as having a fee apply when customers choose a cash agent instead of utilizing the customer lobby available to them. See Exhibit GAS-4.

Second, Ms. Scheier points to a Center for Responsible Lending report as evidence of excessive fees at pay day loan businesses. Again, UNS Gas covers those fees related to the payment of gas bills at locations where it does not have an office. With regard to the suggestion that UNS Gas is somehow encouraging customers to enter into agreements with pay day loan operations, we are not doing so. Customers could make the decision to enter into these agreements even if UNS Gas retained all of its branch offices and the customer needed cash to pay his or her gas bill, or even if there were "ATM-like Kiosks" as Ms. Scheier suggests in her Direct Testimony. After ACAA approached UNS Gas with this concern, I asked location managers whether or not they have experienced UNS Gas bill payers taking out loans to pay their bills. Of the managers asked, none could remember a time that this had happened.

UNS Gas is trying to keep costs for all of its customers down, while maintaining local payment options for those customers who would like to pay their bills in person. I have looked into Ms. Scheier's concerns and we are not encouraging our customers to utilize pay day loan services from these locations.

Q. In her Direct Testimony at pages 2, 10 and 11, Ms. Scheier recommends that UNS Gas bill assistance money be increased to $50,000 and be directed to the statewide non-profit Arizona fuel fund being created and managed by ACAA. What is your response to that?

A. I am uncertain whether Ms. Scheier is referring to the emergency bill assistance funds proposed by the Company to be part of LIW or the Warm Spirit bill assistance program. As I discuss above, we are willing to shift the emergency bill assistance money into the Warm Spirit program and recover for such in base rates. This will allow for more funds to help with bill assistance for our customers. UES Gas would support ACAA in managing the bill assistance money.

Q. Ms. Scheier also recommends on pages 2 and 9 of her Direct Testimony that the LIW funds be increased to $200,000. Do you have any response to this recommendation?

A. As is shown by our proposal to increase LIW funds, I do believe that more money can be used to help the Company's low-income customers. I do not have the necessary information to know just how much money the CAAs can utilize effectively – Ms. Scheier would better be able to provide that support. However, I believe that the CAAs need time to ramp up to support additional funding. The Company commits to work with CAAs prior to its next rate case to discuss additional opportunities. Again, the Company believes that the appropriate cost recovery mechanism for the LIW program, regardless of the amount the Commission ultimately deems appropriate, is through the DSM Adjustor Mechanism as a DSM program.

Q. Do you have any concerns over Ms. Scheier's recommendation that $20,000 in LIW funds be used to fund community volunteer weatherization efforts?

A. I would defer to Ms. Scheier as someone who sees the funds in action everyday to determine how they are best allocated.

Q. Finally, do you have any comments to Ms. Scheier's recommendation that the proposed changes in the Company's billing terms be rejected?

A. I would refer to the comments I made earlier in my Rebuttal Testimony in response to Ms. Diaz Cortez's Direct Testimony on this subject.

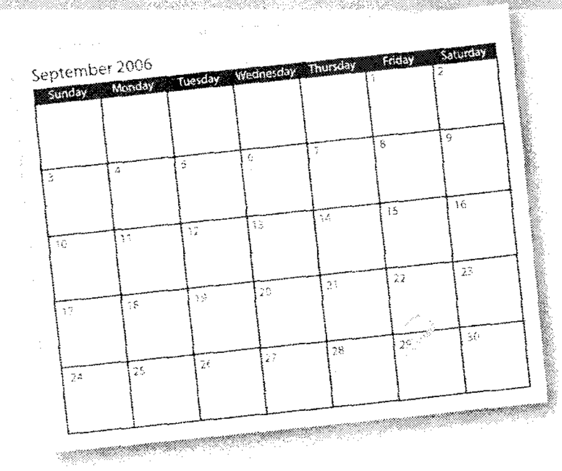
Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

GAS-3

The UES lobby in Cottonwood will be closing on Sept. 29th.



You'll still have plenty of ways to get what you need from UES.

We will be closing the walk-in lobbies at the UES offices in Cottonwood, Prescott, Flagstaff and Show Low because of several factors:

- More and more customers are discovering the convenience of online, telephone and other electronic payment methods (see back for all payment options).
- Cash-paying customers may now visit one of our independent payment agent locations in these four communities (see back for details).
- The handling of cash payments creates a personal safety issue for our employees.
- UES is constantly looking for ways to increase productivity and efficiency. Discontinuing these lobby operations helps keep our costs down, and that helps keep your gas rates down.
- *UES e-bill* is coming soon. It's the ultimate in convenience for receiving, viewing and paying your UES bill online.

Many other customer transactions and inquiries can be handled online at **uesaz.com**, or by calling UES toll-free at **877-UES-4YOU** (877-837-4968).

Our Customer Care Center is open Monday through Friday, 7 a.m. to 7 p.m. to serve you.

UniSourceEnergy SERVICES

See back for payment option details.

UES-Lobby Closure Area 83, 89-8/06

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit ACE Cash Express:

- 989 S. Main, Ste. B, Cottonwood – 928-639-1000 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in one of our convenient drop boxes:

- 500 S. Willard St., Cottonwood (outside of the UES office)
- Sedona Safeway, 2300 W. Highway 89A, Sedona – 928-282-0118

Credit Card, Debit Card or Bank Account Withdrawal

Web – Visit **uesaz.com** to pay your bill online using your credit card, debit card or bank account withdrawal (a convenience fee from a third-party payment processing company will apply).

Telephone – Use your credit card, debit card or bank account withdrawal to pay your UES gas bill via our toll-free payment hotline: **800-284-9730** (a convenience fee from a third-party payment processing company will apply).

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It may not be high-tech, but it gets the job done for your check or money order payment. We supply the envelope, you supply the stamp.

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UES e-bill is the online, fast, simple, convenient, secure, guaranteed, anywhere, anytime, FREE way to pay your UES gas bill. Visit **uesaz.com** and sign up to receive an e-mail notification when this service is available.

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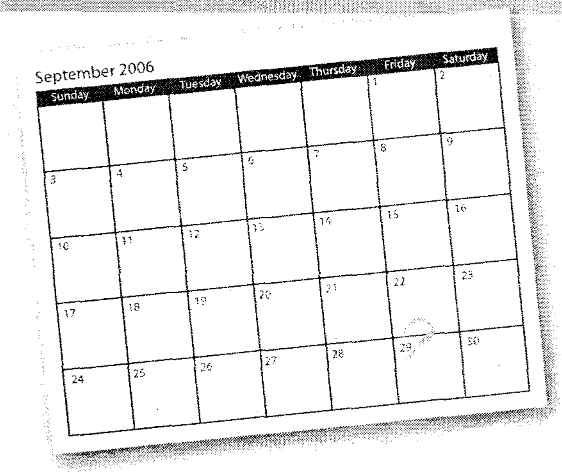
877-UES-4YOU (877-837-4968)

The UES lobby in Flagstaff will be closing on Sept. 29th.



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UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit Ozark Advanced Quick Cash:

- 3470 E. Route 66, Suite 101, Flagstaff – 928-526-5626 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in one of our convenient drop boxes:

- 2901 W. Shamrell Blvd., Ste. 110, Flagstaff (outside of the UES office)
- Flagstaff Safeway, 1500 E. Cedar Avenue, Flagstaff – 928-774-3774
- Flagstaff Safeway, 4910 N. Highway 89, Flagstaff – 928-526-6116
- Flagstaff Safeway, 1201 S. Plaza Way, Flagstaff – 928-779-3401

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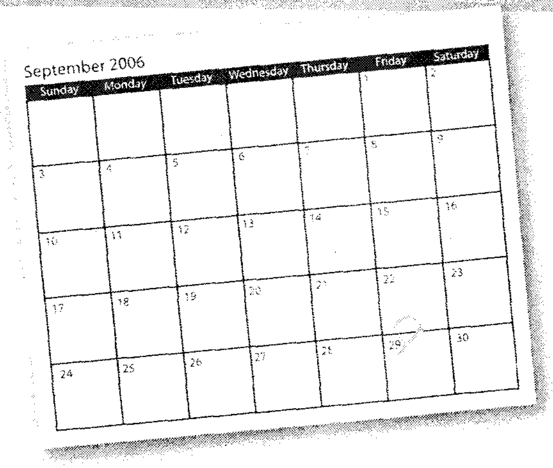
The UES lobby in Prescott will be closing on Sept. 29th.



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UniSourceEnergy SERVICES

See back for payment option details.

UES-Lobby Closure Area 88-8/06

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit ACE Cash Express:

- 621 Miller Valley Road, Prescott – 928-777-0039 (free service)
- 8101 E. Hwy. 69, Ste A, Prescott Valley – 928-759-9939 (free service)
- 1578 N. US-89 Suite A, Chino Valley – 928-636-5545 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in our convenient drop box:

- 6405 Wilkinson Drive, Prescott (outside of the new UES office)

Credit Card, Debit Card or Bank Account Withdrawal

Web – Visit **uesaz.com** to pay your bill online using your credit card, debit card or bank account withdrawal (a convenience fee from a third-party payment processing company will apply).

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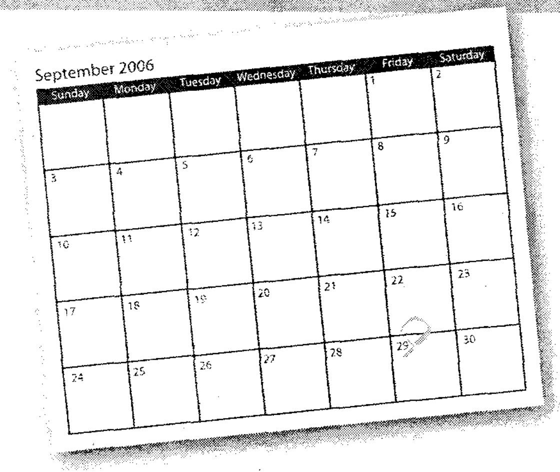

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UES-Lobby Closure Area 84, 85, 91-8/06

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit Audio Advantage/Radio Shack.

- 4431 S. White Mountain Road, Suite 1, Show Low – 928-532-0462 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in one of our convenient drop boxes:

- 1480 N. 16th Street, Show Low (outside of the UES office)
- National Bank of Arizona, 902 E. Deuce of Clubs, Show Low – 928-537-2933
- National Bank of Arizona, 1820 E. White Mountain Blvd., Pinetop – 928-367-0650
- National Bank of Arizona, 718 N. Main Street, Taylor – 928-536-2143

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EXHIBIT

GAS-4

Payment Agents - Microsoft Internet Explorer

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tps://www.uesaz.com/gas/YourBill/Agents.html

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Search Powered by Google

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Gas Services

Payment Agents

- ACE Cash Express Locations
- Additional Cash Only Locations

- Cash only -

- You will be provided with a receipt after cash payment has been made.
- Please verify the accuracy of your account number on your receipt before leaving.
- Please take your bill stub with you. This will help make sure your payment is processed accurately.
- A $1.00 fee will apply at selected locations (see below)

Please note locations below have a UNS Gas, Inc. office nearby

ACE Cash Express Locations

Bullhead City

1812 Highway 95, Ste 20, Bullhead City, AZ 86442 - (928) 763-8865

Store Hours: Monday through Thursday 8:30 a.m. to 6:30 p.m.; Friday 8:30 a.m. to 7:00 p.m.; Saturday 9 a.m. to 5 p.m.; Closed Sunday

Camp Verde

522 Finnie Flats Road, #F, Camp Verde, AZ 86322 - (928) 567-0676

Store Hours: Monday through Friday 9:00 a.m. to 6:00 p.m.; Saturday 9 a.m. to 3 p.m.; Closed Sunday

Internet

Gas Cash Payment Agents - Microsoft Internet Explorer

File Edit View Favorites Tools Help

Back Search Favorites

Address https://www.uesaz.com/gas/YourBill/Agents.html Go Links

Chino Valley

1578 N. US-89 Suite A, Chino Valley, AZ 86323 - (928) 636-5545

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Cottonwood

989 S. Main, Ste B, Cottonwood, AZ 86326 - (928) 639-1000

Store Hours: Monday through Friday 8:30 a.m. to 6:30 p.m.; Saturday 10:00 a.m. to 5:00 p.m.; Closed Sunday

Kingman

3787 Stockton Hill Road, Kingman, AZ 86401 - (928) 692-7110
2785 Northern Ave, Kingman, AZ 86401 - (928) 757-7575
($1 fee will apply)

Store Hours: Monday through Thursday 8 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Fee charged in this location is bolded

Lake Havasu

20 N. Acoma Blvd, Lake Havasu City, AZ 86403 - (928) 854-4447

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Nogales

1965 N. Grand Ave. Nogales, 85621 - (520) 761-3999

Store Hours: Monday through Saturday 9:00 a.m. to 9:00 p.m.; Sunday 10:00 a.m. to 6:00 p.m.

570 W. Mariposa, Nogales, AZ 85621 - (520) 377-2013
($1 fee will apply)

Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Sunday 9:00 a.m. to 4:00 p.m.

43 N. Morley Ave, Nogales, AZ 85621 - (520) 287-7400
($1 fee will apply)

Store Hours: Monday through Saturday 10:00 a.m. to 6:00 p.m.; Sunday 10:00 a.m. to 4:00 p.m.

Fee charged in these locations is bolded

Done Internet

Gas Cash Payment Agents - Microsoft Internet Explorer

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Address https://www.uesaz.com/gas/YourBill/Agents.html Go Links

Prescott

621 Miller Valley Road, Prescott, AZ 86301 - (928) 777-0039

Store Hours: Monday through Thursday 8:00 a.m to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Prescott Valley

8101 E. Hwy. 69, Ste A, Prescott Valley, AZ 86314, (928) 759-9939

Store Hours: Monday through Thursday 9:00 a.m. to 6:30 p.m.; Friday 9:00 a.m. to 7:00 p.m.; Saturday 9:30 a.m. 5:00 p.m.; Closed Sunday

Additional Cash Only Locations

Flagstaff

OA Quick Cash
3470 E. Route 66, Suite 101, Flagstaff AZ 86004
Phone: (928) 526-5626
9:00 a.m. to 5:30 p.m., Monday through Friday
10:00 a.m. to 2:00 p.m., Saturday

Winslow

Winslow Document Express
118 B E. Second St.
Winslow AZ
928-289-3290
Hours: Monday through Friday 9AM to 5PM

Show Low

Audio Advantage/Radio Shack
4431 S. White Mountain Rd., Suite 1, Show Low AZ 85901
Phone: (928) 532-0462

Sedona

Weber IGA Food & Drug
100 Verde Valley School, Sedona AZ 86351
Phone: (928) 284-1144

Done Internet

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-06-463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	)	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	)	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Gas, Inc.

March 16, 2007

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<u>Exhibits</u>

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your position with UniSource Energy Corporation?

A. I am employed by Tucson Electric Power Company ("TEP") as a Lead Analyst in the Pricing and Economic Forecasting department. In this role I prepare cost of service studies and rate design proposals. I also perform these functions for UNS Electric, Inc. ("UNS Electric").

Q. Please describe your education and experience.

A. I earned my Master of Science in Economics from Texas A&M University, and my Bachelor of Arts from the University of Dallas. I have 25 years of utility experience in the areas of cost allocation and rate design, forecasting, valuation and fair market value determination, and utility mergers and acquisitions. I have testified before state regulators in Arizona, Texas and Alabama on these issues. I testified on behalf of TEP in general rates cases during the 1990s on issues related to cost allocation, rate design and unbundling.

Q. What is your role in this case?

A. I am adopting the Direct Testimony filed by Tobin L. Voge, and I am filing this Rebuttal Testimony. I functioned as a lead analyst in developing both testimonies and their associated analyses.

Q. What is the purpose of your Rebuttal Testimony?

A The purpose of my Rebuttal Testimony is to respond to the direct testimonies of Steven W. Ruback, Ralph C. Smith, and Julie McNeely-Kirwan on behalf of the Arizona Corporation Commission, Utilities Division Staff ("Staff"), Marylee Diaz Cortez on behalf of the Residential Utility Consumer Office ("RUCO"), and Miquelle Scheier on behalf of the Arizona Community Action Association ("ACAA").

Q. Please summarize your Rebuttal Testimony.

A. My Rebuttal Testimony focuses on four key issues:

1. Customer Annualization;
2. Rate Design issues involving customer charges;
3. Throughput adjustment mechanism ("TAM"); and
4. Customer Assistance Residential Energy Support ("CARES") discount.

These are the issues where there are significant differences between UNS Gas, Inc. ("UNS Gas" or the "Company") positions, and the positions of Staff, RUCO, and ACAA. The differences are discussed in detail below, but a common thread separates the positions. The Company's proposals are innovative and well-supported. They are superior approaches given the circumstances faced by the Company. Unfortunately, Staff and RUCO appear reluctant to chart new ground, and instead resort to an overly cautious approach of rejecting new ideas in favor of previously-used approaches that do not fit the situation at hand. This is unfortunate because the rate design proposals made by the Company were aimed at helping reduce a grossly unfair subsidy to customers in low-use, desert communities from customers in higher use communities like Flagstaff.

Q. Please summarize this issue of geographical inequity.

A. The key problem presented by the Company's current rate design is that *costs are almost independent of volume, yet current rates are driven primarily by volume.* This means that customers who use larger quantities of gas, like residents in the colder community of Flagstaff, will end up paying more than the Company requires to serve them, because customers in desert communities use little gas, and pay less than the cost to serve them. Colder weather customers, who already have higher bills than their desert counterparts, are then required to subsidize the customers with the low bills. The problem should be easy to solve. Customer charges need to increase to recognize that much of the cost structure on the distribution system is fixed, not volumetric. Unfortunately, Staff and RUCO have summarily rejected the higher customer charges without considering the impacts on Flagstaff and other high-use customers. They have based their rejection on some bill comparisons showing that smaller customers are receiving higher percentage increases. This is an inadequate reason to reject the higher proposed customer charges. Customer charge increases are cost-based and are exactly the prescription required to deal with the geographical inequity. Dealing with the geographical inequity is the single most important policy implication of the Company's proposed rate design.

II. <u>CUSTOMER ANNUALIZATION ADJUSTMENT</u>.

Q. Have the Staff Witness Smith and the RUCO witness Diaz Cortez recommended rejection of the Company's customer adjustment methodology?

A. Yes. Both Mr. Smith and Ms. Diaz Cortez favor a "traditional" method whereby they compare the customer counts in each month of the test year to the December 31, 2005 test year-end level of customers, and then multiply the additional customers attributable to each month by the average revenue per customer for each month, to quantify the additional revenue attributable to the additional customers. Ms. Diaz Cortez calls this the "accepted" method in her Direct Testimony at page 15, line 22 through page 16, line 3.

Q. Is the method just described always the Commission's accepted method?

A. No. In some cases, alternate methods have been proposed and accepted when the traditional method fails to address actual circumstances. The "traditional" method works well when:

i. the number of customers is growing in a stair-step fashion (constant absolute growth each month; linear customers), or the growth rate is constant (and typical of utility customer growth rates) for each month (exponential customer growth); and

ii. new customers to be added after the test year have similar consumption to the average customer in the class (homogeneous customers).

When these criteria are not met, the traditional method can produce erroneous results. An erroneous result could be, for example, that class customers and/or class usage are decreasing when in fact customers and/or usage are increasing. For example, there are cases (e.g., TEP and Arizona Public Service Company) where the largest classes of industrial or commercial customer do no meet either of these criteria. Often there are relatively few industrial customers, and because of the non-homogeneity of class customers, it is unlikely that a new customer will use what the class average customer uses. Consider a hypothetical case where, a huge existing customer will plan to double its size, but at the same time a "borderline" large customer is closing its doors. The impact of the huge customer's expansion may dwarf the loss of the entire borderline large customer. A huge positive customer annualization adjustment may be in order to recognize substantially higher revenue attributable to the huge customer's growth. Yet the simplistic traditional method would result in a negative adjustment simply because the number of customers fell by one – the one being the borderline large customer who is leaving the system. The traditional approach is so easy; unfortunately it is sometimes overly simplistic and wrong.

With the large consumption classes, it is more standard to base a customer adjustment on a "survey approach", where each large customer is studied separately, and the class customer adjustment is calculated on a customer-by-customer basis. The point here is that customer adjustments are not always calculated by some single traditional, accepted method.

Q. Why is the "traditional" method inappropriate in this case?

A. Much of the UNS Gas service area is blessed with the climate and other attributes that make it a favorite destination for seasonal residents. Consequently, the number of gas customers, while growing, follows a recurring cyclical pattern. Residential customers leave the service territory during hot summer months. UNS Gas commercial customers also follow cyclical patterns. As stated above, the "traditional" method works best when customer growth follows a stair step or constant growth pattern. When the number of customers is cyclical, the traditional approach becomes highly sensitive to where the end of the test year falls in the cycle. If the end of the test year falls at September 2005, the end of the trough of the cycle (*i.e.*, if the chosen test year had ended with September, 2005, instead of December, 2005 which was used in this filing), the traditional approach leads to an absurd result – a negative adjustment of 1,181 monthly customers for commercial Rate 20. One cannot explain a negative adjustment – an adjustment that will increase customers' rates – on a growing system. Customers on a system with a positive growth trend in revenue, in customers, and in sales, should never pay more because of some negative customer adjustments calculated using a non-applicable traditional approach. Note that over the 12-month period, the traditional approach yielded negative

Rate 20 adjustments four out of 12 times. In fairness, I must note that one of the 12 adjustments calculated using the Company's approach is negative; the magnitude of the negative adjustment is trivial. The large variation in customer adjustments under the traditional approach renders the results of little use with cyclical customer patterns.

Q. Did you compare the volatility in customer adjustments under the traditional and Company's approach?

A. Yes. I focused my analysis on commercial Rate 20, a class with a cyclical customer pattern. Exhibit DBE-1 (attached) shows that that under the test-year ending December 31, 2005, the Company's approach resulted in a positive adjustment of 844 monthly customers over the test year, while the "traditional" approach resulted in 2,024 monthly customers over the test year. Larger customer adjustments add operating income to the test year and are in the customers' benefit, so the questions is to ask whether the UNS Gas approach consistently favors the Company. The result is that the Company's approach shows no favoritism. Exhibit DBE-1 shows that, for Rate 20, in the 12 different test years (*i.e.*, 12 different overlapping test years comprised of months from 2004 and 2005, with the exception of one last test year which is all from 2005; test years have successive ending months; the first test year being February 2004 through January 2005, the second being March 2004 to February 2005, and so forth -- ending with months January 2005 through December 2005, that six months have "traditional" annualizations exceeding "Company-approach" annualizations. For the other six months, Company's approach annualizations were higher.

The mean annualization for Rate 20 customers was almost the same – with the Company's approach being ever so slightly (in these cases) in the customers' benefit. The results for Rate 20: 1,274 monthly customers for the Company's approach vs. 1,240 for the "traditional" approach. From the standpoint of only the mean of the annualizations, the two approaches produce practically the same result. However, one must be careful about just looking at the mean. For example, San Diego, California and Wichita Falls, Texas have almost the same average annual temperature (64 and 63 degrees Fahrenheit respectively). If one plans to book a vacation, however, be aware that the standard deviation in Wichita Falls' temperature is higher than San Diego's temperature. Wichita Falls' mean monthly temperatures run from 40 to 85 degrees Fahrenheit; San Diego's from 57 to 73 degrees Fahrenheit. This means that if you randomly pick your vacation date, you are more likely to weather closer to the average in San Diego than in Wichita Falls.

The Company's approach to customer adjustments, like San Diego's temperature, has a lower standard deviation than the traditional approach. For the Company's approach, the standard deviation in the adjustment is 673 monthly customers. For the "traditional approach", the standard deviation is 1,746 monthly customers, over 2.5 times as much volatility as the Company-approach. The standard deviation under the traditional approach is even more than the mean. The customer adjustment based on the traditional approach is so volatile its validity with the UNS Gas customer data is questionable. The basic problem here is that one's choice of the start of the test year has a drastic and unintended impact on the customer adjustment under the traditional approach. Using the Company's method is more likely to result in the type of positive customer adjustment one would expect with a growing system. The cyclical behavior in number of customers renders the traditional approach useless. Consequently, I continue to recommend the Company's approach.

III. <u>RATE DESIGN</u>.

Q. On page 27, line 17 of Ms. Diaz Cortez's Direct Testimony, she states that the UNS Gas rate design proposal will "create rate shock for some customers, result in perverted price signals, and stifle conservation." Do you agree with these assertions?

A. No. While some customers would face an adjustment period with the new rates, it is difficult to predict whether customers will be "shocked." Actually, UNS Gas' proposed rate design sends more accurate price signals than the existing structure, because it is more cost-based. Further, since a volumetric rate is still part of the overall structure, and because customers will pay volumetrically for the cost of gas through the purchased gas adjustor ("PGA"), customers will still have ample incentive to conserve. Therefore, I do not agree with any of Ms. Diaz Cortez's assertions.

Q. Are the Company's proposed rates appropriate price signals?

A. Yes. The Company's proposed rates are appropriate signals; however, the Company's current rates are not. The Company has increased customer charges for proposed rates, to recognize the system's substantial fixed costs. Distribution costs are largely fixed. The installed cost of the distribution plant components (*i.e.,* pipe, meters, regulators) as well as expense components (*i.e.,* meter reading and billing) do not vary (over relatively wide ranges represented by a class' customers' usage) with the volume of natural gas flowing through the system. Consequently, the distribution costs for individual customers within the residential class are generally independent of household usage. Higher proposed customer charges recognize this fact, and help bring the non-commodity portions of residential gas bills closer together. This price signal (higher customer charges) under the proposed rates more effectively reflects the reality of usage-insensitive costs.

The key problem presented by the Company's current rate design is that *costs are almost independent of volume, yet current rates are driven primarily by volume.* If there is a perversion in the Company's rate design, it comes from this mismatch in current rates.

In moving to a more cost-based design, the Company's proposed higher customer charges acknowledge higher "fixed" costs that vary little with usage. Higher proposed customer charges enable UNS Gas to cut proposed volumetric charges. Under the Company's proposal, higher use customers will see smaller percentage increases in bills. The current structure, regrettably burdens the average residential customer in Flagstaff with approximately $292 in annual margin, while the average customer in Lake Havasu pays only $159 in annual margin. The margins paid should be closer together. (Flagstaff will still have a higher bill because the Flagstaff customer must pay for more of the natural gas commodity). The current fixed cost recovery predominantly through volumetric rates creates incorrect price signals for our customers. As Ms. Diaz Cortez states in her Direct Testimony at page 28, line 13, the Company collects nearly three quarters of its revenue through commodity rates. (For clarification, the revenue referenced here is distribution margin revenue, and does not include revenue for the recovery of the cost of natural gas.)

That is too much recovery from volumetric charges. The UNS Gas proposal to shift more cost recovery from a volumetric rate to a monthly customer charge is an attempt to send the appropriate price signal and alleviate the disparity that currently exists between our cold and warm climate customers.

Q. Could you further explain why you disagree with the assertion that the Company's rate design proposal will stifle conservation?

A. I disagree because this assertion ignores the impact of the cost of natural gas in encouraging conservation among customers. The current and projected price of natural gas ranges from 60 to 70 cents per therm. This cost of gas provides a strong incentive to reduce consumption. The combination of our proposed distribution rate and the cost of natural gas results in a total rate of approximately 80 to 90 cents per therm for residential customers. The total cost of gas at this level will motivate customers to seek conservation opportunities.

Q. Did Ms. Diaz Cortez provide any evidence in her Direct Testimony supporting her claim that the UNS Gas rate design proposal will stifle conservation?

A. No, she merely states that high users will see a decrease in bills and low users will see an increase as a result of the margin rate going from the current 30 cents per therm to the proposed 18 cents per therm. She then concludes this would all but halt any incentive for conservation. Yet she presents no evidence that a 12-cent decrease in the margin rate will elicit an apathetic response toward conservation among customers while an opportunity to avoid a 60 to 70 cent per therm in natural gas cost exists.

Q. Did any intervenor witnesses address the geographic subsidy that you identified in your Direct Testimony?

A. No, neither Staff nor RUCO directly address this rate design inequity in their Direct Testimonies. Both RUCO and Staff state that their respective proposals generate more revenues through the customer charge than is currently generated. However, the proposed $1.50 per month increase by Staff and the $1.13 per month by RUCO for residential customers results in the continued subsidization of fixed costs by customers in cold climates.

Q. Have any intervenor witnesses disputed the results of the UNS Gas cost of service study which substantiates a monthly charge for residential customers of nearly $26?

A. No. Although UNS Gas has presented evidence that distribution costs are essentially fixed and could be entirely recovered through a monthly customer charge, the rate designs proposed by Staff and RUCO depend considerably on a volumetric rate component for cost recovery. One cannot tell from the Direct Testimony whether any serious cost of service based consideration was given by Staff and intervenors to the Company's customer charge proposals.

Too often, innovative approaches are discarded by simply contending that they violate "gradualism," or will cause "rate shock," or will not gain "public acceptability." I believe that Staff and intervenors often fail to recognize consumer adaptability, and the desire of consumers for cost based rates. The notions of "gradualism" and "public acceptability" should be applied in the context of the current consumer experience. While relatively low gas and electric customer charges for gas and electricity service may be the norm in Arizona, consumers have seen some common products move away from volumetric pricing and toward higher customer charges that establish tiers of service. This is common in the pricing of telephone, cable television, and internet service.

Q. Did you propose the full residential customer charge of $26 that you supported in your analyses?

A. No. The Company-proposed residential customer charge averages $17. That means that substantial levels of fixed costs would still be collected on a volumetric basis under the Company's proposal. Consequently, the intervenors claim that the Company's rate design eliminates revenue volatility and "guarantees return" are a gross exaggeration. The claims are even more exaggerated under the Staff's and RUCO's residential customer charge proposals, whereby the residential customer charge is increased by only $1.50 and $1.13 by Staff and RUCO, respectively.

Q. Mr. Steven W. Ruback for Staff states in his Direct Testimony at page 5, lines 7 through 9 that seasonal customer charges "are also not appropriate because the customer costs included in a customer charge do not change by season." Do you have any comments about that statement?

A. Yes. It is an interesting statement considering Staff's proposed rate design. Mr. Ruback seems to be using a cost-of-service argument against seasonal customer charges. But Staff's proposed rate design gives very little deference to the cost of service study. UNS Gas does seek more certainty that rates will recover costs. This is a natural consequence of cost-based rates. From a policy standpoint, the most important consequence of implementing the Company's cost-based rates is a reduction in the subsidization of customers in low-use desert communities by customers in high-use communities like Flagstaff. The public interest demands an end to this inequity. Cost-based rates dictate higher customer charges. The Company has proposed customer charges that greatly alleviate this degree of subsidization of one town by another and believes the public interest supports such a design. The seasonal customer charge was simply a means to help levelize the total bills over the 12 month period. The seasonal differential was never intended to reflect customer cost by season. What is important is that $204 in customer charges gets collected over the 12 months. UNS Gas would not be averse to levelizing the proposed customer charge over the year, so long as $17 per month for residential customers is collected. UNS Gas's seasonal design was intended to make gas bills easier to budget for over the year.

Q. Why does UNS Gas' proposed rate design not violate any long-standing regulatory principles as Mr. Ruback alleges in his Direct Testimony?

A. Under UNS Gas' proposed rate design, the Company still has to depend on volumetric rates to achieve its authorized rate of return. Moreover, costs must be controlled. When return is calculated, one must consider both revenue and cost. UNS Gas' proposed rate design is hardly a guarantee of the authorized rate of return. Increased revenue stability is a necessary consequence moving toward more cost-based rates for UNG Gas. One cannot be a cheerleader for cost based rates and throw mud on revenue stability in this case. Contrary to Mr. Ruback's Direct Testimony, the Company is not given any guarantee through its proposed rate design. The Company's proposed design violates no long- standing regulatory principles.

Q. Has the Company considered the impact of these higher customer charges on customers?

A. Yes. However, it is important to recognize that with higher customer charges come lower volumetric charges, other things constant. Moreover, the seasonal customer charges discussed above were proposed to help customers budget for their gas bills. Significantly lower winter customer charges will be especially helpful in cool weather areas like Prescott and Flagstaff.

IV. <u>THROUGHPUT ADJUSTMENT MECHANISM ("TAM")</u>.

Q. At page 31, line 2, in her Direct Testimony, Ms. Diaz Cortez asserts that the TAM would entirely remove any risk associated with revenue recovery. Do you concur?

A. No. First, the Company will continue to bear all risk associated with recovery of margin costs from those customers whose Pricing Plans are not subject to adjustment through the TAM. Second, the TAM is intended to true up the revenue requirement of participating customers established in the test year. Therefore, the TAM will not adjust for increases in revenue requirement beyond the test year, such as additional costs associated with labor or plant in service.

Q. On page 32, line 9 in her Direct Testimony, Ms. Diaz Cortez states that minimizing the impact of weather on customers bills is not necessarily a desirable feature for a gas rate design. Do you agree with this statement?

A. No. I believe that breaking the link between recovery of fixed costs and customer usage is appropriate in gas rate design. During a colder than normal winter, customer bills will be higher as a result of increased consumption. When fixed cost recovery occurs through the volumetric margin rate, customers pay more "fixed costs" than they would have under normal weather conditions, even though the Company has not incurred additional fixed costs due to increased throughput. An objective of equitable rate design should be to insulate customers from the burden of additional margin charges in a period of higher than normal consumption.

Q. Would the TAM compromise the Company's willingness and incentive to control costs and afford it a guaranteed return on equity?

A. No. The Company has a strong incentive to control costs with or without the TAM in place. Any cost escalation between rate cases negatively impacts the Company's earnings. The TAM will true up for deviations from the baseline cost recovery established in this case for certain classes of customers. The TAM will not recover increased expenses or plant not already included in rates, so the Company has incentive to keep costs down. Further, because plant will have to be added to meet customer growth, any opportunity to earn its authorized return on equity will likely be eroded. In short, this type of true up does not provide a guarantee that the Company will earn its authorized return on equity.

Q. Do you believe that the implementation of the TAM would adversely impact conservation?

A. No. Ms. Diaz Cortez overstates the customer price response induced by the TAM adjustment. Using historical rates of decline in consumption as shown in Exhibit TLV-2 of my Direct Testimony as an estimate, the annual adjustment to the margin rate will likely be less than one cent per therm. The cost of natural gas at 60 to 70 cents per therm will continue to provide a strong incentive for conservation.

Q. Ms. Diaz Cortez and Mr. Ruback cite Commission denial of a decoupling mechanism in the Southwest Gas Corporation rate case in Decision No. 68487 (February 23, 2006) as support for denial in this case. What is your response?

A. Ms. Diaz Cortez and Mr. Ruback failed to note the following paragraph from Decision No. 68487 at page 34, lines 14 through 17:

> We encourage the parties in this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders. To that end, Southwest Gas should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRC and any other interested parties.

It is evident that the Commission supports the continued evaluation of decoupling mechanisms for Southwest Gas and presumably other Arizona gas utilities. The UNS Gas rate design proposal meets the tenets set forth above; it encourages conservation efforts and benefits stakeholders. The expansion of the Demand-Side Management ("DSM") program, as described in Mr. Gary A. Smith's Direct Testimony for UNS Gas, clearly promotes conservation. The symmetrical nature of the TAM benefits stakeholders by minimizing the impact of weather on customer bills and the Company's financial situation.

Q. Has there been support for decoupling mechanisms?

A. Certainly. Attached to my Rebuttal Testimony as Exhibit DBE-2 is a statement from the American Gas Association ("AGA") made on February 12, 2007 before the United States Senate – Energy and Natural Resources Committee. That statement makes the following observations:

- Under the prevailing system of cost recovery, most natural gas utilities are adversely affected when their customers consume less natural gas because they recover a less-than-expected share of the costs of operating their network systems.
- Recent events show that our gas markets are particularly vulnerable to interruptions, with dire consequences for customers.
- Reduced consumption of natural gas tends to have a negative impact upon the bottom line of natural gas utilities, thus giving consumers and natural gas utilities very different perspectives on energy efficiency and conservation.
- The costs of the distribution service – the service to delivering gas to customers – that natural gas utilities provide does not vary much in relation to the amount of gas that utilities' customers consume.
- By disconnecting a utility's revenue stream from the volume of gas actually delivered, utility interests and consumer interests are aligned in promoting energy efficiency. Even slight gains in efficiency have the potential to reduce natural gas prices.

In short, by adopting the TAM, the Commission will help break the dependence of UNS Gas on natural gas consumption as the means to earn its return.

Q. Is there support for decoupling mechanisms other than among the natural gas utility industry?

A. Yes. The Natural Resources Defense Council ("NRDC"), the American Council for an Energy-Efficient Economy ("ACE^3") and the AGA issued a joint statement in July 2004 to the National Association of Regulatory Utility Commissioners ("NARUC") supporting "mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales." The NRDC and AGA both recognize that innovative programs are needed to best align the interests of shareholders, customers, and state regulators towards promoting energy conservation and increased efficiencies. Both also noted that natural gas utilities are hurt when promoting energy efficiency when the utilities must also ensure the safe and reliable delivery to homes, schools, hospitals and other customers and ensure that natural gas is available for these customers 24 hours a day and seven days a week. Because volumetric rates link natural gas consumption to meeting its revenue requirements, there is significant financial disincentive for natural gas utilities to encourage customers to use less natural gas. So, the NDRC – which hardly can be considered an industry group – agrees that decoupling mechanisms like the TAM can best align all interests so that all can strive to achieve energy efficiency. This statement is attached to my Rebuttal Testimony as Exhibit DBE-3.

I also note here that this joint statement warns against reducing authorized returns if a decoupling mechanism is adopted. That would "penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills."

In addition, NARUC adopted a resolution attached to my Rebuttal Testimony as Exhibit DBE-4 on November 16, 2005, encouraging State commissions to reconsider rate designs and implement innovative rate designs like "decoupling tariffs." This resolution occurred subsequent to the July 14, 2004 resolution cited in Mr. Ruback's Direct Testimony.

Q. Mr. Ruback makes a reference to a terminated "Electric Revenue Adjustment Mechanism" from Maine in support for his position against the TAM. Do you have a response to that?

A. I am skeptical that the mechanism he cites from Maine in effect from the early 1990s has much relevance to what UNS Gas faces now in light of unprecedented natural gas price volatility and the moves it has made toward actively supporting DSM and other energy efficiency programs. In any event, it appears from Mr. Ruback's own Direct Testimony that the problems with Maine's mechanism stem from a $52 million revenue deferrals. The TAM here is designed to recovery any revenue deficiency yearly so such a large deferral is next to impossible.

Q. How many states have adopted decoupling mechanisms?

A. There are at least ten states. Those states are: California, Delaware, Indiana, Maryland, New Jersey, North Carolina, Ohio, Oregon, Utah and Washington. The District of Columbia has also adopted a decoupling mechanism.

V. CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT ("CARES").

Q. Ms. McNeely-Kirwan claims that the proposed changes to the CARES program would have a disproportionate impact on low-usage CARES customers and eliminate the incentive to conserve provided by the current per therm discount. What is your response?

A. I do not agree with either of Ms. McNeely-Kirwan's statements. First, I believe that the UNS Gas' proposed rate design in its entirety – and not just the CARES discount – will have a positive impact for all low-usage residential customers. The objective of the Company's rate design proposal is to correct for the existing subsidy high usage customers in cold climates provide to their counterparts in warm climates. Elimination of this inequity should apply to both non-CARES and CARES customers.

Also, a CARES customer will see less of an annual bill increase than a standard residential customer at a similar level of consumption. For a summer consumption of 35 therms per month, a residential customer will see an increase of $9.00 per month and a CARES customer will see an increase of $2.50 per month (Schedule H-4, pages 1 and 2). Given a winter consumption of 75 therms, a residential customer will see a decrease of $4.56 per month while a CARES customer will see an increase of $0.22 per month. The annual increase for a residential customer at this level of usage is approximately $30 and $21 for the CARES customer.

I also do not agree with the statement that the UNS proposal has eliminated the incentive to conserve provided by the current per therm discount. The current after-discount margin rate for CARES is $0.1504 per therm during the winter months, for the first 100 therms. The UNS Gas proposal is $0.1862 per therm for all therms in all months. It is doubtful that a price difference of $0.0358 per therm during the winter will have a significant influence in a CARES customer's conservation behavior. But the price of gas will still provide a strong incentive for low-income customers to conserve. Further, UNS Gas is committed to the low-income weatherization program to help give these customers the means to conserve. In short, all customers, even low-use low-income customers will have the incentive to conserve.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DBE-1

UNS Gas
Net Change in Monthly Customers
Attributable to Weather Adjustment

Erdwurm-Rebuttal
Exhibit 1

Rate 20 Results.

Line	Test Year Starts	Test Year Ends	Company's Approach	Traditional Approach
1	Jan-05	Dec-05	844	2,024
2	Dec-04	Nov-05	(120)	(152)
3	Nov-04	Oct-05	256	(1,133)
4	Oct-04	Sep-05	1,610	(1,181)
5	Sep-04	Aug-05	1,872	(558)
6	Aug-04	Jul-05	1,980	228
7	Jul-04	Jun-05	1,860	1,020
8	Jun-04	May-05	1,663	2,244
9	May-04	Apr-05	1,804	3,184
10	Apr-04	Mar-05	1,243	3,547
11	Mar-04	Feb-05	1,000	2,801
12	Feb-04	Jan-05	1,274	2,859
		Mean	1,274	1,240
		Standard Deviation	673	1,746
		Median	1,442	1,522

EXHIBIT

DBE-2

STATEMENT
OF THE AMERICAN GAS ASSOCIATION

ON

ENERGY EFFICIENCY PROGRAMS

BEFORE THE
UNITED STATES SENATE
ENERGY AND NATURAL RESOURCES COMMITTEE

FEBRUARY 12, 2007

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EXECUTIVE SUMMARY

The American Gas Association represents 200 local energy utility companies that deliver natural gas to more than 64 million homes, businesses and industries throughout the United States. Natural gas meets one-fourth of the United States' energy needs and has historically been the fastest growing major energy source. Adequate supplies of competitively priced natural gas are of critical importance to AGA and its member companies. Similarly, ample supplies of reasonably priced natural gas are of critical importance to the more than sixty million consumers that AGA members serve. AGA speaks here for those consumers as well as its member companies.

Natural gas is the cleanest fossil fuel. When combusted it produces less carbon than any other fuel. Importantly, almost all of the natural gas consumed in America is produced in North America. Thus, from the perspective of both its environmental benefits and its contribution to America's energy security, natural gas is nearly the perfect fuel.

Throughout the 1990's natural gas producers, for a variety of reasons, had significant excess production capacity. As a result, gas prices were consistently in the $2-3 range per million British Thermal Units (MMBtu). In the winter of 2000-2001 natural gas prices rose dramatically. Initially, the general belief was that this spike was an aberration and that new exploration and production efforts spurred by these higher prices would bring additional supply online, and prices would fall concomitantly. To the surprise of almost all involved, this did not occur, and, over time, it became clear that in fact the higher prices were the result of a more systemic underlying problem. New producing areas, which in fact hold prolific supplies of natural gas that could meet America's needs for many decades, were unavailable for exploration and production as a result of a number of federal policies. Accordingly, those in the exploration and production business (which AGA does not represent) have had no choice but to focus on mature areas, where even maintaining current levels of natural gas output requires increasing degrees of effort and financial investment.

As this situation developed, it began to become clear that ameliorating high natural gas prices for consumers would require not only efforts aimed at encouraging more natural gas supply but also efforts aimed at increasing the nation's level of energy efficiency. With the supply-demand situation remaining so narrowly in balance, <u>either</u> modest increases in supply or modest decreases in consumption can have a dramatic effect on the prices consumers pay.

Even prior to the dramatic price increases of 2000-2001, natural gas had achieved a remarkable level of efficiency. The average American home today uses 25% less natural gas than it did in 1980. Similar trends have occurred in the commercial and industrial sectors of the customers served by natural gas utilities. Moreover, data recently compiled by AGA reveal that, since the winter of 2000-2001, Americans have reduced their natural gas consumption at even a more accelerated rate.

Natural gas utilities that deliver natural gas to homeowners generally have two parts to their prices. The first part is the charge for the gas commodity itself. Natural gas utilities essentially act as agents for their customers, buying natural gas for them on an aggregated basis. State public service commissions oversee this process, and they require utilities to sell this gas to their customers without markup or profit. Natural gas is a commodity traded in various wholesale markets that are not unlike those for oil, wheat, corn, and pork bellies.

The second part of the price charged by utilities is the cost of delivering the natural gas to customers. The vast majority of these costs, like those of other network industries, are the capital costs of the delivery network itself. Historically, the cost of providing utility service has been recovered on a "volumetric" basis, subject to oversight and regulation by state public service commissions. In shorthand terms, all of the costs of operating the utility for the year are distributed over the estimated volume of deliveries for the year. If the utility ultimately delivers that exact number of units, then it exactly recovers its costs of delivering gas for the year. If it ultimately delivers fewer units, then it recovers less than all of the costs of operating its system.

Under this prevailing system of cost recovery, most natural gas utilities are adversely affected when their customers consume less natural gas because they recover a less-than-expected share of the costs of operating their network systems. Thus, customers that desire to conserve energy or become more energy efficient and utilities that deliver natural gas have divergent financial interests.

There is a solution, however, to this conundrum. Over the last five years a number of states have "decoupled" natural gas utility rates in order to align the energy-efficiency interests of consumers and natural gas utilities. Although there are many ways to do so, the essence of these programs is to "decouple" the utility's recovery of its system costs from the volume of natural gas delivered through its system, which is also known as "throughput." The result is that the utility recovers the costs of operating its system independent of whether the volume of natural gas it delivers declines as a result of energy efficiency or conservation. Nine states have now embraced some form of decoupling, which breaks the link between utility earnings and customer consumption.

In a "decoupled" environment, the interests of the consumer and the utility are aligned. In a "decoupled" environment the interests of energy efficiency are served because there is no financial disincentive for a utility to promote and encourage efficiency. For these reasons there has been a growing movement in the states to adopt decoupled revenue-recovery mechanisms for natural gas utilities.
In a decoupled regulatory regime, natural gas utilities and their customers can work together to implement natural gas efficiency programs.

Natural Gas Prices Are Likely to Remain at Today's High Levels Into the Future

Since the winter of 2000-2001, the natural gas industry has been at a critical crossroads. Natural gas prices were relatively low and very stable for most of the 1980s and 1990s. Wholesale natural gas prices during this period tended to fluctuate around $2-3 per MMBtu. Over the course of the past five years, however, natural gas markets have been supply constrained. Even small changes in weather, economic activity or world energy trends result in significant wholesale natural gas price fluctuations. As a result, our industry walks a supply tightrope, bringing with it unpleasant and undesirable economic and political consequences—most importantly high prices and higher price volatility. These consequences strain natural gas customers—residential, commercial, industrial, and electricity generators.

As this committee well knows, energy is the lifeblood of our economy. Millions of Americans rely upon natural gas to heat their homes, and high prices are a serious drain on their pocketbooks. Small businesses depend on natural gas for space heating, hot water, cooking, clothes drying, cooling and dehumidification, small-scale electricity generation and other applications. The impacts of high, volatile natural gas prices on U.S. industries – including plant closings and unemployment - are well documented. The impacts on small businesses may be less obvious but they are no less significant. Directly or indirectly, natural gas is critical to every American.

The consensus of forecasters is that natural gas demand will increase steadily over the next two decades. The electricity generation market will continue to drive this growth (even more so should we adopt a national climate change policy), as natural gas has been the fuel of choice for over 90 percent of the new generation units constructed over roughly the past decade. In part, the dominance of natural gas in this market is attributable to environmental regulations that promote the clean-burning characteristics of natural gas. The overall growth in gas usage will occur because natural gas is the most environmentally friendly fossil fuel and is an economic, reliable, and homegrown source of energy.

The consensus of forecasters also is that we shall never return to the era of $2-3 natural gas. The more recent era of $6-7 natural gas will characterize the years ahead absent aggressive national policy changes to promote the production of large amounts of the prodigious natural gas resources that North America enjoys.

Moreover, recent events show that our gas markets are particularly vulnerable to interruptions, with dire consequences for consumers. In September 2005 multiple hurricanes in the Gulf of Mexico eliminated nearly 25 percent of our total gas supply for a brief period. The hurricanes resulted in prices that fluctuated between $12.00 and $14.00 per MMBtu, and a brief cold snap in December 2005 produced a price spike to roughly $15.00 per MMBtu. Only a substantially warmer than normal 2005-2006 winter heating season has dampened the impact of these price increases to consumers. Clearly, natural gas markets are higher and more volatile than at any point in history. Moreover, there is no sign that this market volatility will abate in the near future.

It is harmful to small businesses, individual families and to the entire U.S. economy for natural gas prices to remain both high and volatile. Unless we make the proper public policy choices—and quickly—we will face many more difficult years with regard to natural gas prices.

This Committee knows well AGA's position with regard to making more natural gas supply available for America's homes, businesses, and industry. The Committee has received AGA's views on this important topic on a number of occasions over the last five year. AGA will continue to pursue additional land access for the environmentally benign production of natural gas.

The goal, of course, is to provide adequate supplies of reasonably priced energy to Americans. Increasing natural gas supply is only one half of that process. Energy efficiency measures is the other half of providing more reasonably priced natural gas.

Energy Efficiency Can Bring Down The Cost of Natural Gas

The natural gas industry has been a national leader in energy efficiency. Today, the average American home uses about 25% less natural gas than it did a quarter century ago. That reduction in per-capita natural gas use has been driven primarily by energy efficiency. Homeowners have conserved by adding storm windows, insulation, and weather stripping to their homes. Over the past twenty-five years gas appliances have become enormously more efficient. Moreover, new construction, although producing increasingly larger homes, has also produced increasingly energy-efficient homes. These trends have also been seen in both the commercial and industrial sectors of the industry.

Information very recently compiled by AGA suggests that in fact natural gas consumers have increased their energy efficiency efforts since prices increased dramatically in 2000-2001. Over the past five years, homeowners have reduced their natural gas consumption more than the 1% per year that has been the trend over the last twenty-five years. It is uncertain at this point what the exact slope will be of this reduction curve in the years ahead.

Energy efficiency brings gas consumers benefits in terms of lowering their energy bills as well as lowering their carbon emissions. What consumers do not understand, however, is the impact energy efficiency can have upon natural gas prices. An MMBtu of natural gas that is not consumed is no different from a new MMBtu that is produced. Either adds to the gap between productive capacity and demand. Most commentators recognize that increasing natural gas supply or decreasing natural gas demand by only several percent can bring natural gas prices down by 10%, 20%, or more. Thus, the customer that becomes more energy efficient not only saves on its energy bill. It also plays a major role in bringing natural gas prices down for all.

There are, of course, many ways that energy efficiency in the natural gas industry can be continued and indeed improved. AGA will not address those at the moment but will instead address a relatively simple way to promote energy efficiency that has been drawing increasing attention across the United States. The traditional structure of natural gas delivery rates puts natural gas utilities and natural gas consumers at odds in terms of promoting energy efficiency. Reduced consumption of natural gas tends to have a negative impact upon the bottom line of natural gas utilities, thus giving consumers and natural gas utilities very different perspectives on energy efficiency and conservation.

Decoupling Natural Gas Utility Rates Encourages Energy Efficiency

Natural gas utilities are network industries. They typically deliver natural gas from the point where their facilities interconnect with long-line interstate natural gas pipelines to energy consumers—whether they are residential, commercial or industrial. Natural gas utilities essentially provide two different services to their residential customers:

First, natural gas utilities act as merchants in acquiring natural gas for their customers. They aggregate the requirements of all of their customers who desire to purchase natural gas, and they purchase these requirements in various wholesale markets. (In most states industrial customers purchase their own gas. In some states with "retail choice" programs, residential customers also may purchase gas from an entity other than their local utility.) In their "merchant" function natural gas utilities purchase gas in markets that are not unlike markets for oil, corn, wheat, or other commodities. The natural gas utility merchant function is thoroughly regulated by state public service commissions. Utilities are not permitted to mark up the cost of gas or to make a profit on it. Rather, in most states utilities pass these costs on to customers pursuant to state-regulated revolving accounts usually known as Purchased Gas Adjustments, Gas Cost Recovery factor, or something similar.

Second, natural gas utilities deliver gas to their customers. They perform this service whether they have purchased the gas as merchant on behalf of the customer or the customer has purchased the gas itself. The charge for this delivery service is calculated in an entirely different fashion—and entirely separately from—the charge for purchased gas. It is usually calculated under traditional public utility cost-of-service ratemaking principles. As with the purchase of gas for customers, it is determined under the supervision and regulation of the state public service commission.

The charge for natural gas delivery service has traditionally been determined under a form of ratemaking known as "volumetric" rates. Under this methodology, the costs of operating the natural gas delivery service are estimated for a year and then allocated to the projected volumes of gas that will be delivered over that year. Thus, for each unit of gas delivered by the utility the customer pays a small portion of the cost of operating the utility. Should a utility deliver more gas in a year than projected, it will (all other things being equal) earn more than its projected costs. Should a utility deliver less gas in a year than projected, then it will (all other things being equal) earn less than the projected costs of operating its system.

A short example may make this situation more understandable. Assume that the costs of operating utility delivery service are $100 per year. This is composed of operations and maintenance expense of $65, depreciation of assets of $8, taxes of $12, and return on invested debt and equity capital of $15. Assume also that it is projected that the utility will deliver 100 units of gas per year. In this instance, the unit cost of delivering natural gas will be $1. Should consumers install new energy efficient appliances during the year such that actual deliveries are 95 units, then the utility receives delivery revenue of $95. This is less than the actual cost of operating the service. The $5 shortfall drops straight to the bottom line and represents a diminution in the utility's return on equity.

This example makes plain that, under a volumetric form of rate design, energy efficiency and energy conservation can be injurious to the shareholders of the natural gas utility, particularly if it turns out to be more significant than projected in the ratemaking process. The consumer has an interest in minimizing its energy bill. The utility has an interest in providing its expected return on capital to its shareholders (who all ultimately are energy consumers as well).

A fundamental, and probably immutable, fact is that natural gas utilities are fixed-cost businesses. The costs of the distribution service that they provide do not vary much in relation to the amount of gas that the utilities' customers consume.

As noted previously, natural gas consumers have, over the past twenty-five years, reduced their consumption by twenty-five percent, or approximately one percent per year. Over the past five years the most recent data indicate that this trend has accelerated. Although what the exact trend will be in the future is unclear, there is no indication that the trend of natural gas consumers to conserve will stop.

This fact, that traditional utility rate design may discourage energy efficiency, has been recognized on a number of fronts over the past five or more years. Fortunately, it can be corrected relatively easily. The solution is to decouple (*i.e.*, disconnect) a utility's revenue stream from the volume of gas actually delivered. This is not by any means a radical or unsound policy. Most of a utility's costs are fixed—that is, they do not vary with the volume of service delivered. Moreover, most utility's systems are sized to be able to meet deliveries on the peak cold day of the winter. From a ratemaking perspective, therefore, it is by no means irrational to suggest that the revenue should be recovered independent of the volume of gas delivered.

This model has almost universally been adopted in the cable television industry. The customer pays the same amount per month regardless of how many different channels are watched or how many hours the cable box is on. Similarly local telephone service is largely recovered through a fixed monthly charge. Both of these industries are similar to natural gas distribution in that they have large capital costs, most of their costs are fixed, and the network system is sized to meet peak demand.

Many states, as well as federal policy makers, now encourage energy efficiency and conservation. Consequently, several states have put in place rate mechanisms that "decouple" the recovery of distribution system delivery costs from the volume of gas delivered to customers. Doing so frees the utility to promote conservation and energy efficiency actively without a detriment to its shareholders.

There are variety of ratemaking devices that can be implemented to achieve decoupling. One is "straight fixed-variable" rate design. Under that approach, all of the costs of operating the utility system are collected in twelve monthly charges. This is the system used by the Federal Energy Regulatory Commission for interstate natural gas pipelines.

Another somewhat different method is weather normalization. This method takes the effects of differing weather (which is perhaps the largest determinant of volumes in the natural gas delivery business) out of the revenue stream. It does not, however, take into account the effects of energy efficiency or conservation. A related approach might be called "efficiency normalization." Like weather normalization, it takes the effects of efficiency and conservation gains out of the utility's revenue stream. In Oregon, for example, the utility actually compares consumption over time on a customer-by-customer basis to make an adjustment to rates to make the utility whole for the effects of conservation and efficiency.

The essence of revenue decoupling, however, effectuated, is to adjust the actual delivered volumes to the weather-normalized volumes underlying the last rate case of the natural gas utility. When delivered volumes deviate from the level forecasted in the rate case, the true-up mechanism adjusts the distribution charge.

Decoupling is also a fair and efficient means to design utility rates from the customer's perspective. The symmetrical nature of decoupling prevents the utility from increasing its earnings by increasing its delivered volumes because any additional distribution charges collected by the utility in that event are, one way or another, refunded to customers. Moreover, decoupling does not shelter the utility from the impact of increased costs or provide a guarantee that the company will achieve its authorized return on equity. To be clear, decoupling is not "incentive regulation" because there is no reward or bonus for the utility.

An independent evaluation of the Oregon decoupling tariff[1] found the program to be worthwhile and in the public interest. The evaluators found that the mechanism is effective in reducing the variability of utility revenues; removes disincentives to promote energy efficiency; changes the company focus from sales advertising to conservation advertising; does not reduce the incentive for good customer service; and does not shift risk to customers.

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[1] A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural, Christensen Associates Energy Consulting, LLC, March 2005.

At present nine states have adopted some form of revenue decoupling, and a number more are considering it.[2] Decoupling has taken a number of forms in these states, depending upon their individual needs, circumstances, and policies. In some of these states, decoupling is linked to public benefit funding that is aimed directly at energy efficiency.

The beneficial nature of decoupling is not simply a view of AGA and the natural gas utility. AGA and the Natural Resources Defense Council have adopted a joint declaration concerning the value of decoupling.[3] Furthermore, the National Association of Regulatory Utility Commissioners, the trade association of state public service commissioners, has adopted a resolution urging the states to review their practices to determine whether innovative rate designs of this sort can assist in bringing natural gas costs down.[4]

Conclusion

Traditional rate design contains a financial disincentive that may inhibit utilities from aggressively promoting energy efficiency and conservation. Revenue decoupling breaks the link between a utility's earnings and energy consumption of its customers. The utility therefore becomes financially indifferent to the declining volumes associated with energy conservation and efficiency. The experience to date with decoupling shows that it has aligned consumer interests with utility interests and made utilities enthusiastic partners in promoting efficiency. Even slight gains in efficiency have the potential to reduce natural gas prices significantly.

[2] A map of states that have adopted or are considering decoupling is attached.
[3] A copy is attached.
[4] A copy is attached.

EXHIBIT

DBE-3

American Gas Association

NRDC

THE EARTH'S BEST DEFENSE

American Council for an Energy-Efficient Economy

Joint Statement of the American Gas Association, the Natural Resources Defense Council and the American Council for an Energy-Efficient Economy

Submitted to the National Association of Regulatory Utility Commissioners
July 2004

The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not profit from their acquisitions of natural gas to serve customer needs. The profit (authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.[1] We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

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[1]For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. *See* Oregon PUC Order No. 02-634, *Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the expectation that weather will be normal, on average, and that customer use of gas will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

Natural Gas Consumers, Price Volatility and Resource Portfolio Management. Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

L:NRDC-AGA Statement – FINAL-June, 2004

EXHIBIT

DBE-4

Resolution on Energy Efficiency and Innovative Rate Design

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review the incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response; *and*

WHEREAS, The NARUC at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit,"* which encouraged the NARUC Natural Gas Task Force to review the findings and recommendations of the September 23, 2003 report by the National Petroleum Council on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy* and its recommendations for improving and promoting energy efficiency and conservation initiatives; *and*

WHEREAS, The NARUC at its 2004 Summer Meetings, adopted a *Resolution on Gas and Electric Energy Efficiency* encouraging State commissions and other policy makers to support expansion of energy efficiency programs, including consumer education, weatherization, and energy efficiency and to address regulatory incentives to inefficient use of gas and electricity; *and*

WHEREAS, These NARUC initiatives were prompted by the substantial increases in the price of natural gas in wholesale markets during the 2000-2003 period when compared to the more moderate prices that prevailed throughout the 1990s; *and*

WHEREAS, The wholesale natural gas prices of the last five years largely reflect the fact that the demand by consumers for natural gas has been growing steadily while, for a variety of reasons, the supply of natural gas has had difficulty keeping pace, leading to a situation where natural gas demand and supply are narrowly in balance and where even modest increases in demand produce sharp increases in price; *and*

WHEREAS, Hurricanes Katrina and Rita, in addition to damaging the States of Alabama, Mississippi, Louisiana, and Texas, significantly damaged the nation's onshore and offshore energy infrastructure, resulting in significant interruption in the production and delivery of both oil and natural gas in the Gulf Coast area; *and*

WHEREAS, The confluence of a tight balance of natural gas supply and demand and these natural disasters has driven natural gas prices in wholesale markets to unprecedented levels; *and*

WHEREAS, The present high and unprecedented level of natural gas prices are imposing significant burdens on the nation's natural gas consumers, whether residential, commercial, or industrial, and will likely be injurious to the nation's economy as a whole; *and*

WHEREAS, The recently enacted Energy Policy Act of 2005 contains a number of provisions aimed at encouraging further natural gas production in order to bring down prices for consumers, but these actions, together with any further action on energy issues by Congress, are unlikely to bring forth additional supplies of natural gas in the short term; *and*

WHEREAS, Energy conservation and energy efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices and to assist in bringing energy prices down, to the benefit of all natural gas consumers; *and*

WHEREAS, Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), other options (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas; *and*

WHEREAS, Current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers; *now therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its November 2005 Annual Convention in Indian Wells, California, encourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices; *and be it further*

RESOLVED, That NARUC recognizes that the best approach toward promoting energy efficiency programs for any utility, State, or region may likely depend on local issues, preferences, and conditions.

Sponsored by the Committee on Gas
Recommended by the NARUC Board of Directors November 15, 2005
Adopted by the NARUC November 16, 2005

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

Denise A. Smith

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. What is your employment position?

A. I am the Director of Conservation and Renewable Programs at Tucson Electric Power Company, UNS Gas, Inc. ("UNS Gas" or the "Company") and UNS Electric, Inc ("UNS Electric") (collectively the "UniSource Energy Companies").

Q. Please describe your education and professional background.

A. I graduated from Northern Arizona University ("NAU") in 1991 earning a Bachelor of Science degree in Mathematics with an extended major in Statistics and then completed graduate work in Statistics at NAU. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix. After leaving NAU, I was hired by Pima Association of Governments in 1992 in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employee's travel to and from work.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In addition, I implemented and reported progress of existing DSM programs and then transitioned them into market-transformation programs. In 1999, I moved into the Pricing and Rates Department, developing cost of service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. I then accepted the position of Director of Conservation Services. Most recently my position was expanded to include

Renewable Programs. I manage the successful TEP Guarantee Home Program and, for the past year, have been researching and developing new DSM programs for all three UniSource Energy Companies.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Rebuttal Testimony is to respond to certain recommendations made by Ms. Julie McNeely-Kirwan on behalf of Commission Staff with regard to DSM matters.

Q. Did you file Direct Testimony in this proceeding?

A. No, I did not. However, due to my close involvement in the proposal, analysis, monitoring and reporting of DSM programs for the Company, I was asked to respond to Ms. McNeely-Kirwan's Direct Testimony.

Q. Will you also be responding to Ms. McNeely-Kirwan's Direct Testimony on topics other than DSM?

A. No. Mr. D. Bentley Erdwurm responds to certain comments made by Ms. McNeely-Kirwan with regard to the customer service charge and its impact on the Customer Assistance Residential Energy Support ("CARES") program and can answer questions regarding the functioning of the DSM Adjustor Mechanism. Mr. Gary Smith responds to her Direct Testimony on Warm Spirits.

Q. Please summarize your Rebuttal Testimony.

A. My Rebuttal Testimony focuses on Ms. McNeely-Kirwan's recommendations about the DSM programs themselves and for ease of review, tracks Ms. McNeely-Kirwan's Direct

Testimony on these issues. In general, UNS Gas agrees with the majority of Staff's recommendations about DSM. However, as discussed in more detail below, there are a few recommendations from Ms. McNeely-Kirwan that we are requesting be modified.

II. <u>DEMAND SIDE MANAGEMENT</u>.

A. Benefits and Costs of DSM

Q. In her Direct Testimony – at page 9, lines 18-21 – Ms. McNeely-Kirwan urges the consideration of the benefits and costs of DSM to society and states that the Commission has adopted the use of the Societal Cost Test. Do you have any response?

A. Yes. I believe that Ms. McNeely-Kirwan's description of Decision No. 57589 (October 29, 1991) merits clarification. Ms. McNeely-Kirwan is correct that the Commission expressed a preference for the Societal Cost Test back in 1991. As an initial matter, however, it is not clear that Decision No. 57589 applies the Societal Cost Test to DSM. Specifically, on page 25 of Decision No. 57589, the Commission summarized its order and stated that one of its objectives is to adopt the Societal Cost Test "for all new power plants."

Even assuming that the Societal Cost Test was intended to be applied to all resource planning, including DSM, the Commission was careful to note that the Societal Cost Test must be tempered with economic concerns, such as ratepayer concerns, utility financial stability and economic growth within the service areas. While Ms. McNeely-Kirwan is correct that the Commission directed that environmental concerns be considered in resource planning, the Commission was clear in its objective that such concerns must be balanced with other important considerations:

> This Commission wants to state loudly and clearly that it has <u>a goal to have financially sound utilities and reasonable rates for consumers, while at the same</u>

> time minimizing the effect on our fragile environment. Even though the primary focus of this docket was on resource planning and environmental concerns, it is our firm commitment to strive for the proper balancing of all three of the above listed concerns.

See Decision No. 57589 at 24. (Emphasis in original).

In order to strike the right balance, the Commission ordered that a task force be formed to "identify and quantify the various environmental costs and other externalities such as resource diversity, land use, or economic development." Decision No. 57589 at 10. The task force was directed to identify costs to be included in the Societal Costs and outline how costs are to be quantified and/or monetized. It was also to address the suitability of evaluating costs on a qualitative basis when they could not be quantified or monetized. I am not aware of the Commission adopting any recommendations of the task force. Thus, questions still remain about the Societal Cost Test as to (1) what costs are to be included in the Societal Cost Test, and (2) how these costs are to be treated in evaluation. No determination has ever been made as to how these benefits and costs are to be measured. UNS Gas believes the test it has applied in this case – namely the Total Resource Cost Test ("TRC") - is a more concrete, quantitative analysis that should be used in order to understand the costs and benefits of DSM measures.

In several places throughout her Direct Testimony, Ms. McNeely-Kirwan makes reference to societal costs and benefits (*See e.g.* page 23, line 15; page 24, line 4; page 30, line 10). I would point out again, such costs and benefits have not been formally adopted by this Commission.

Q. On page 10, Ms. McNeely-Kirwan goes on to describe the societal costs of a DSM program. Do you have any comments about her description?

A. Again, I am unaware that the Commission has adopted any formal definition of societal costs with regard to DSM programs.

B. Current DSM Programs.

Q. At page 11, at lines 2-4 in her Direct Testimony, Ms. McNeely-Kirwan recommends that the Company submit detailed program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case. Do you have any response to this recommendation?

A. UNS Gas will file detailed program proposals as soon as possible. However, I would note that our cost benefit analyses were conducted assuming some economies of scope and scale through joint program implementation of some measures with UNS Electric. Because we believe that taking advantage of such economies are appropriate, the program proposals that we will file will assume some joint program implementation and administration.

Q. What information will be included in the detailed program proposals?

A. UNS Gas is working to refine the previous analysis and program descriptions based on Staff's recommendations. We have updated the avoided costs numbers to be consistent through-out the UniSource Energy Companies for all DSM evaluations. In addition, we corrected a few errors in the efficiency calculations and provided greater detail in the documentation for the cost benefit calculations. An analysis of the low income weatherization ("LIW") program was also completed to identify energy savings associated with measures installed through that program. UNS Gas is also updating the program descriptions with the information requested by Ms. McNeely-Kirwan as well as including information requested on the overall DSM portfolio. UNS Gas has combined the Commercial Cooking Program and the Commercial HVAC Retrofit into one program to allow customers to choose the measures that serve their needs while achieving economies of scale to minimize administrative and overhead costs.

Q. Also in her Direct Testimony, at page 14, lines 11-13, Ms. McNeely-Kirwan recommends that the therm savings and cost-effectiveness of the LIW program should be determined. Do you have any response to this recommendation?

A. It is difficult to determine the therm savings and cost-effectiveness of the existing LIW program with precision, given the wide variety of weatherization activities that can occur and the differing degrees to which they are installed and the limited records provided to UNS Gas. Even so, we have asked the Northern Arizona Council of Government ("NACOG") to provide some information to help assess the savings resulting from the LIW program. Attached as Exhibit DRS-1 is a letter received from Ms. Margaret Keener, NACOG's LIW Program Manager. She provides information regarding the weatherization measures implemented on the homes.

Ms. Keener estimates that weatherization efforts result in a 20 percent reduction in household energy use at a minimum. In addition, UNS Gas provides funds that are leveraged to acquire additional funds from government agencies. Numbers provided by NACOG suggest that for every dollar supplied by UNS Gas, NACOG is able to leverage about $1.32 from government sources. In other words, customers receive $2.32 worth of energy efficiency improvements for every $1.00 UNS Gas applies.

Q. Can you provide an estimate of the annual therm savings per LIW participant?

A. Yes, through an analysis of customer data through 2006 and confirming through test-year data (Schedule H-2, page 1). A customer qualifying for the LIW program also qualifies for CARES participation. A general review of all CARES customer annual gas consumption indicates that a typical 2006 CARES customer consumes about 500 therms per year. Using NACOG's statement that a LIW project must achieve at least a 20 percent annual energy consumption reduction, I estimate that annual gas consumption reductions of at least 100 therms for each LIW participant under a cursory analysis of the existing program.

However, as described below, UNS Gas is taking steps to better determine savings for the LIW program on a going forward basis.

Q. Ms. McNeely Kirwan describes – at page 15 at lines 16-26 in her Direct Testimony – several cost-effectiveness tests and concludes that UNS should include data required to calculate each of its proposed programs on a Societal Cost Test basis. Do you have response to her description or her suggestion?

A. UNS Gas believes that proper DSM evaluation involves the use of several DSM cost-effectiveness tests. This is consistent with the Commission's objective in Decision No. 57589 to carefully balance environmental concerns with economic concerns. In addition, the October 2001 California Standard Practice Manual "Economic Analysis of Demand Side Management Programs and Projects," attached hereto as Exhibit DRS-2, recognizes the importance and limitations of the Participant test, Ratepayer Impact Measure ("RIM"), TRC test and Program Administrator Cost Test. The Societal Cost Test is defined as a subset of the TRC test in that manual. Given the advances in DSM program evaluation testing described in the October 2001 California Standard Practice Manual, the Commission should now encourage utilities to use a wider spectrum of the cost effectiveness evaluation tools available when reviewing possible DSM programs for submittal to the Commission for approval.

In addition and as I discussed above, the manner in which the Societal Cost Test was to be calculated was to be determined by the task force per Decision No. 57589, assuming the Societal Cost Test applied to DSM programs. Again, the Commission does not appear to have adopted any particular calculation. In the interest of cooperation, however, we will include a form of the Societal Cost Test. In order to reach Societal Cost Test results, TEP replaced the utility capital discount rate with a societal discount rate and quantified the environmental benefits that are expected to result from DSM measures installed in terms of pounds of Carbon Dioxide.

C. Proposed New Programs.

Q. Do you have any response to Ms. McNeely-Kirwan's recommendation at page 20, lines 1-2, that UNS Gas provide information regarding verification and inspection of the LIW program in its program proposals?

A. UNS Gas intends to set up a database to better track the installations made through the LIW program. Proposed modifications to the LIW program design provide UNS Gas the ability to better determine therm savings from weatherization measures in future years. A defined list of weatherization measures and equipment replacement has been identified for use by the agencies who deliver the LIW program for UNS Gas. Engineering simulations determine the deemed therm reduction from installation of each measure. The new process will require weatherization agencies to collect and report more detailed information about the work completed in each household. With an appropriate amount of detail about products or equipment removed and products or equipment installed, UNS Gas can apply deemed savings calculations to determine therm savings and cost effectiveness of the program. This should address Ms. McNeely-Kirwan's concerns regarding verification and inspection of the LIW program.

D. Program Administration and Implementation.

Q. Do you have any response to Ms. McNeely-Kirwan's recommendations on pages 21 to 23 concerning the Company's filing of a portfolio plan?

A. The Company will file a portfolio plan and individual DSM program proposals for those programs it recommends be implemented for UNS Gas customers. The Company will endeavor to include all of the information requested by Ms. McNeely-Kirwan and will file this information as soon as possible. I would note, however, that her requested information includes societal costs and benefits of each measure or program and, as I discuss earlier in my Testimony, the Commission has not defined these societal costs and benefits.

E. Monitoring and Evaluation.

Q. On pages 23 to 25 of her Direct Testimony, Ms. McNeely-Kirwan makes some recommendations with regard to monitoring DSM programs. As an initial matter, do you agree that monitoring DSM is a productive activity?

A. Yes. I agree with Ms. McNeely-Kirwan that it is important to periodically analyze DSM programs to make sure that they are operating effectively, to determine if improvements should be made, and to discontinue those programs that no longer make sense for our customers. In order to do so, we propose a baseline study. This baseline study is necessary to establish the current level of deployment and saturation of energy efficiency technologies in the market, assess the level of market penetration that each program may be able to realize over time, identify opportunities for additional energy efficiency improvements and collect data for market and technology characteristics to support future program planning and evaluation and measurement activities. Examples of the kind of information collected in a baseline study include:

- Non-residential and residential facility types and characteristics (e.g., square footage, vintage);
- Equipment types and characteristics;
- Saturation of energy system technologies;
- Energy system operational characteristics; and
- Current practices of energy system specifics and designers.

UNS Gas seeks approval to begin the process of selecting a contractor and conducting the baseline study. Since the baseline study performance characteristics for most of the efficiency measures included in the plan are already well known and the cost-effectiveness of most measures has been confirmed, UNS Gas seeks approval to launch selected programs concurrently with the execution of the baseline study.

Q. Do you object to creating a monitoring plan for each program and describing such in the program proposals?

A. No, the Company will draft and submit monitoring plans for each of its DSM programs.

Q. Do you agree with the information requested to be filed in semi-annual reports?

A. While the Company is willing to provide the Commission with the information requested by Ms. McNeely-Kirwan, the Company requests that such reporting be done annually, as opposed to semi-annually. If the Company is permitted to report the information annually, it believes that it will be able to do a more comprehensive report within 90 days after the end of each year. In addition, since gas consumption in the UNS Gas territory tends to be winter seasonal, a one-year reporting interval is far more meaningful in providing program results information than a six-month interval.

F. Marketing and Advertisement of the UNS Gas DSM Programs.

Q. Do you agree with the Staff's recommendation on page 26 of Ms. McNeely-Kirwan's Direct Testimony that UNS Gas provide more detailed information regarding the marketing of LIW in its program proposal?

A. Yes. The marketing of the LIW program is conducted by the outside agencies currently administering the program. However, I would be happy to contact those agencies and ask them to provide additional information regarding their marketing efforts.

G. Cost Recovery of DSM Programs.

Q. Do you agree with the Staff's analysis of the appropriate cost recovery mechanism for DSM programs that Ms. McNeely-Kirwan describes in her Direct Testimony at pages 27 to 28?

A. Yes. Ms. McNeely-Kirwan is correct that DSM costs should be timely recovered, cost recovery should be flexible, and these costs are not appropriately placed in the purchase gas adjustor. I further agree with her that DSM costs should be transparent to ratepayers. Thus, we are in agreement that a DSM adjustor mechanism is the most appropriate way to recover DSM costs.

Q. Ms. McNeely-Kirwan recommends that by January 31 of each year, UNS should file information to set the DSM adjustor charge. Do you have any response to this recommendation?

A. The Company would not have the necessary data by January 31 to file for the next year. We would request that the filing be made on April 1 of each year. This would move an annual adjustment back to May 15 or June 1, given Ms. McNeely-Kirwan's proposed timing that she describes in her Direct Testimony. UNS Gas is happy to provide the information requested by Ms. McNeely-Kirwan.

Q. In her Direct Testimony at pages 29 to 30, Ms. McNeely-Kirwan states that initially only funding for LIW should be placed in the DSM Adjustor Mechanism. Do you have any comments?

A. While I believe the intent of Ms. McNeely-Kirwan's recommendation is to eliminate funding for those programs not yet in operation, the Company is close to implementing several programs and her recommendation would preclude the Company from recovering start-up costs for those programs for several months. In order to begin to timely recover start-up costs, I would propose that LIW funds ($113,400), as well as 50 percent of the funds estimated for the new DSM programs ($460,000) be included in the DSM Adjustor Mechanism immediately upon the Commission rendering a decision in this case.

Q. Are there any other costs that should be included in the DSM Adjustor Mechanism right away?

A. Yes. As mentioned above, consistent with Ms. McNeely-Kirwan's recommendation that the Company implement meaningful monitoring and evaluation of DSM programs, the Company seeks cost recovery to commission a baseline study. The costs associated with the baseline study are properly recovered through the DSM Adjustor Mechanism.

Q. What would the initial DSM charge be, if the Commission approves your recommendations to recover 50 percent of the other DSM programs plus the costs to commission a baseline study?

A. The initial charge would be $0.004148 per therm, resulting in a $0.20 monthly charge for the average residential customer using 48 therms per month.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DAS-1

Northern Arizona Council of Governments

119 EAST ASPEN AVENUE • FLAGSTAFF, ARIZONA 86001-5222
(928) 774-1895 • FAX (928) 773-1135 • E-MAIL: nacog@nacog.org

KENNETH J. SWEET
EXECUTIVE DIRECTOR

February 28, 2007

Tom Hansen
Vice President
Tucson Electric Power
P.O. Box 457
St. Johns, AZ. 85936

Dear Mr. Hansen:

Northern Arizona Council of Governments (NACOG) Weatherization Program's low-income recipients have hugely benefited from Unisource contributions.

Households who receive Weatherization assistance live with poverty level incomes ($10,210 for a household of one; $20,650 for a household of four). Large utility bills impact low-income families. Utilities consume a larger portion of the low-income family's income than they consume of the higher income family's income. About 20% of a low income family's income is used for utilities compared to 5% for a higher income family. Low-income persons must often make monthly decisions as to whether to pay rent or mortgage, pay utilities, or buy food.

The Weatherization Program performs diagnostic tests and installs energy saving measures on homes in order to reduce the family's energy burden and make the home more energy efficient. First, the Weatherization program performs a computerized energy audit on the home. The audit results define the measures that will save energy and make the home more energy efficient. Only those measures that will contribute to a minimum 20% energy savings are accomplished. Second, the Weatherization crews install those elements which make the home more energy efficient and reduce the family's energy burden.

Last year NACOG received $39,000 from Unisource and assisted twenty-one families in the Unisource gas service areas in Navajo, Coconino, and Yavapai counties. The Unisource investments were partnered with the federal Department of Energy (DOE) and Low Income Home Energy Assistance Program (LIHEAP) funds. The maximum Unisource investment was $2,000. Sample measures taken were the installation of attic insulation, replacement of non-operating doors, and replacement of leaky, broken windows with dual-pane windows.

By combining limited resources with Unisource, there were energy savings of 20% to 40% in each home.

About eighty percent of the home that the NACOG Weatherization program assists are older mobile homes. The difference for the lives of the low income participants is in warmth, health, safety, and less income depletion. There is an advantage to the neighborhood as Weatherization helps stabilize the affordable housing stock. There is a saving to society also as the cumulative energy demand is reduced.

Please contact me if you wish any further information.

Thank you for your concern for the less fortunate customers of Unisource.

Sincerely,

Margaret Keener

Margaret Keener
Division Chief

EXHIBIT

DAS-2

CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

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Chapter 1

Basic Methodology

Background

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. Conservation and load management (C&LM) programs have been implemented in California by the major utilities through the use of ratepayer money and by the CEC pursuant to the CEC legislative mandate to establish energy efficiency standards for new buildings and appliances.

While cost-effectiveness procedures for the CEC standards are outlined in the Public Resources Code, no such official guidelines existed for utility-sponsored programs. With the publication of the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* in February 1983, this void was substantially filled. With the informal "adoption" one year later of an appendix that identified cost-effectiveness procedures for an "All Ratepayers" test, C&LM program cost effectiveness consisted of the application of a series of tests representing a variety of perspectives-participants, non-participants, all ratepayers, society, and the utility.

The Standard Practice Manual was revised again in 1987-88. The primary changes (relative to the 1983 version), were: (1) the renaming of the "Non-Participant Test" to the "Ratepayer Impact Test"; (2) renaming the All-Ratepayer Test" to the "Total Resource Cost Test."; (3) treating the "Societal Test" as a variant of the "Total Resource Cost Test;" and, (4) an expanded explanation of "demand-side" activities that should be subjected to standard procedures of benefit-cost analysis.

Further changes to the manual captured in this (2001) version were prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for "cost effective conservation and energy efficiency" for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the Spring of 2001, a distribution charge to provide revenues for a self generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the Spring of 2001, a new state agency — the Consumer Power and Conservation Financing Authority — was created. This agency is expected to provide additional revenues in the form of state revenue bonds that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities.

The modifications to the Standard Practice Manual reflect these more recent developments in several ways. First, the "Utility Cost Test" is renamed the "Program Administrator Test" to include the assessment of programs managed by other agencies. Second, a definition of self generation as a type of "demand-side" activity is included. Third, the description of the various potential elements of "externalities" in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the the policy rules that accompany this manual.

Demand-Side Management Categories and Program Definitions

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation' in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer's thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to demand-side management in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures maybe applicable in a new context. AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Hence, self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation. In some cases, self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The combined impact of the new facility is *load building* since the new facility can draw up to 0.5 MW from the grid, even when the DG unit is running. The proper characterization of each type of demand-side management program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to, install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e., to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program — sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in this manual to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

Basic Methods

This manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table I summarizes the cost-effectiveness tests addressed in this manual. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement refers to the way of expressing test results that are considered by the staffs of the two Commissions as the most useful for summarizing and comparing demand-side management (DSM) program cost-effectiveness. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

This manual does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g., groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program-funding levels. For example, for summary tables in general rate case proceedings at the CPUC, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost-effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table I
Cost-Effectiveness Tests

Primary	Secondary
Participant	
Net present value (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW) Net present value	Lifecycle revenue impact per unit Annual revenue impact (by year, per kWh, kW, therm, or customer) First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value (NPV)	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in this manual is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

It should be noted that for some types of demand-side management programs, meaningful cost-effectiveness analyses cannot be performed using the tests in this manual. The following guidelines are offered to clarify the appropriated "match" of different types of programs and tests:

1. For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts.

2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.

3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.

4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in **Table 1** is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in this manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning.

Balancing the Tests

The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives are outside the scope of this manual. The manual, however, does provide a brief description of the strengths and weaknesses of each test (Chapters 2, 3, 4, and 5) to assist users in qualitatively weighing test results.

Limitations: Externality Values and Policy Rules

The list of externalities identified in Chapter 4, page 27, in the discussion on the Societal version of the Total Resource Cost test is broad, illustrative and by no means exhaustive. Traditionally, implementing agencies have independently determined the details such as the components of the externalities, the externality values and the policy rules which specify the contexts in which the externalities and the tests are used.

Externality Values

The values for the externalities have not been provided in the manual. There are separate studies and methodologies to arrive at these values. There are also separate processes instituted by implementing agencies before such values can be adopted formally.

Policy Rules

The appropriate choice of inputs and input components vary by program area and project. For instance, low income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual. Implementing agencies traditionally have had the discretion to use or to not use these inputs and/or benefits on a project- or program-specific basis. The policy rules that specify the contexts in which it is appropriate to use the externalities, their components, and tests mentioned in this manual are an integral part of any cost-effectiveness evaluation. These policy rules are not a part of this manual.

To summarize, the manual provides the methodology and the cost-benefit calculations only. The implementing agencies (such as the California Public Utilities Commission and the California Energy Commission) have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.

Chapter 2

Participant Test

Definition

The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Benefits and Costs

The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings[1].

In the case of fuel substitution programs, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. For load building programs, participant benefits include an increase in productivity and/or service, which is presumably equal to or greater than the productivity/ service without participating. The inclusion of these benefits is not required for this test, but if they are included then the societal test should also be performed.

The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.

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[1] Gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program.

How the Results can be Expressed

The results of this test can be expressed in four ways: through a net present value per average participant, a net present value for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is net present value for the total program; discounted payback, benefit-cost ratio, and per participant net present value are secondary tests.

The discounted payback is the number of years it takes until the cumulative discounted benefits equal or exceed the cumulative discounted costs. The shorter the discounted payback, the more attractive or beneficial the program is to the participants. Although "payback period" is often defined as undiscounted in the textbooks, a discounted payback period is used here to approximate more closely the consumer's perception of future benefits and costs.[2]

Net present value (NPVp) gives the net dollar benefit of the program to an average participant or to all participants discounted over some specified time period. A net present value above zero indicates that the program is beneficial to the participants under this test.

The benefit-cost ratio (BCRp) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. The benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk. A benefit-cost ratio above one indicates a beneficial program.

Strengths of the Participant Test

The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates.

For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits.

For fuel substitution programs, the Participant Test can be used to determine whether program participation (i.e. choosing one fuel over another) will be in the long-run best interest of the customer. The primary means of establishing such assurances is the net present value, which looks at the costs and benefits of the fuel choice over the life of the equipment.

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[2] It should be noted that if a demand-side program is beneficial to its participants (NPVp ≥ 0 and BCRp ≥ 1.0) using a particular discount rate, the program has an internal rate of return (IRR) of at least the value of the discount rate.

Weaknesses of the Participant Test

None of the Participant Test results (discounted payback, net present value, or benefit-cost ratio) accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Until or unless more is known about customer attitudes and behavior, interpretations of Participant Test results continue to require considerable judgment. Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects.

Formulae

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

NPV_P	=	Bp - Cp
NPVavp	=	(Bp - Cp) / P
BCRp	=	Bp / Cp
DPp	=	Min j such that Bj > Cj

Where:

NPVp	=	Net present value to all participants
NPVavp	=	Net present value to the average participant
BCRp	=	Benefit-cost ratio to participants
DPp	=	Discounted payback in years
Bp	=	NPV of benefit to participants
Cp	=	NPV of costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
J	=	First year in which cumulative benefits are cumulative costs.
d	=	Interest rate (discount)

The Benefit (Bp) and Cost (Cp) terms are further defined as follows:

$$BP = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PA_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Where:

BRt	=	Bill reductions in year t
Bit	=	Bill increases in year t

TCt	=	Tax credits in year t
INCt	=	Incentives paid to the participant by the sponsoring utility in year t[3]
PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax[4] • Ongoing operation and maintenance costs include fuel cost • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PACat	=	Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)
Abat	=	Avoided bill from alternate fuel in year t

The first summation in the Bp equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for Bp.

Note that in most cases, the customer bill impact terms (BRt, BIt, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BRt formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times (K_{it} - 1)) + OBI_t$$

Where:

ΔEG_{it}	=	Reduction in gross energy use in costing period i in year t
ΔDG_{it}	=	Reduction in gross billing demand in costing period i in year t
$AC:E_{it}$	=	Rate charged for energy in costing period i in year t

[3] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate must be included in the PC_t term

[4] If money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g., a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

$AC:D_{it}$	=	Rate charged for demand in costing period i in year t
K_{it}	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (e.g.,, customer charges, standby rates).
OBI_t	=	Other bill increases (i.e. customer charges, standby rates).
I	=	Number of periods of participant's participation

In load management programs such as TOU rates and air-conditioning cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs.

If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

Chapter 3

The Ratepayer Impact Measure Test[5]

Definition

The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Benefits and Costs

The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements and are included for both fuels for a fuel substitution program. The increase in revenues are also included for both fuels for fuel substitution programs. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program,* the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in revenues and the increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings.

How the Results can be Expressed

The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle revenue impact, expressed as the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) and the net present value. Secondary test results are the lifecycle revenue

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[5] The Ratepayer Impact Measure Test has previously been described under what was called the "Non-Participant Test." The Non-Participant Test has also been called the "Impact on Rate Levels Test."

impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio. LRI_{RIM} values for programs affecting electricity and gas should be calculated for each fuel individually (cents per kWh or dollars per kW and cents per therm) and on a combined gas and electric basis (cents per customer).

The lifecycle revenue impact (LRI) is the one-time change in rates or the bill change over the life of the program needed to bring total revenues in line with revenue requirements over the life of the program. The rate increase or decrease is expected to be put into effect in the first year of the program. Any successive rate changes such as for cost escalation are made from there. The first-year revenue impact (FRI) is the change in rates in the first year of the program or the bill change needed to get total revenues to match revenue requirements only for that year. The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This series shows the cumulative rate change or bill change in a year needed to match revenues to revenue requirements. Thus, the ARIRIM for year six per kWh is the estimate of the difference between present rates and the rate that would be in effect in year six due to the program. For results expressed as lifecycle, annual, or first-year revenue impacts, negative results indicate favorable effects on the bills of ratepayers or reductions in rates. Positive test result values indicate adverse bill impacts or rate increases.

Net present value (NPV_{RIM}) gives the discounted dollar net benefit of the program from the perspective of rate levels or bills over some specified time period. A net present value above zero indicates that the program will benefit (lower) rates and bills.

The benefit-cost ratio (BCR RIM) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. A benefit-cost ratio above one indicates that the program will lower rates and bills.

Strengths of the Ratepayer Impact Measure (RIM) Test

In contrast to most supply options, demand-side management programs cause a direct shift in revenues. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program.

An additional strength of the RIM test is that the test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building). This makes the RIM test particularly useful for comparing impacts among demand-side management options.

Some of the units of measurement for the RIM test are of greater value than others, depending upon the purpose or type of evaluation. The lifecycle revenue impact per customer is the most useful unit of measurement when comparing the merits of programs with highly variable scopes (e.g.,, funding levels) and when analyzing a wide range of programs that include both electric and natural gas impacts. Benefit-cost ratios can also be very useful for program design evaluations to identify the most attractive programs or program elements.

If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle cost per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results. Of course, this requires developing lifecycle, annual, and first-year revenue impact estimates for the supply-side project.

Weaknesses of the Ratepayer Impact Measure (RIM) Test

Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

RIM test results are also sensitive to assumptions regarding the financing of program costs. Sensitivity analyses and interactive analyses that capture feedback effects between system changes, rate design options, and alternative means of financing generation and non-generation options can help overcome these limitations. However, these types of analyses may be difficult to implement.

An additional caution must be exercised in using the RIM test to evaluate a fuel substitution program with multiple end use efficiency options. For example, under conditions where marginal costs are less than average costs, a program that promotes an inefficient appliance may give a more favorable test result than a program that promotes an efficient appliance. Though the results of the RIM test accurately reflect rate impacts, the implications for long-term conservation efforts need to be considered.

Formulae: The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM), benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = I
ARIRIMt	=	FRIRIM	for t = I
	=	(CRIMt - BRIMt)/Et	for t=2, ..., N
NPVRIM	=	BRIM-CRIM	

BCRRIM` = BRIM/CRIM where:

LRIRIM = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRIRIM = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARIRIM = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI RIM')

NPVRIM = Net present value levels

BCRRIM = Benefit-cost ratio for rate levels

BRIM = Benefits to rate levels or customer bills
CRIM = Costs to rate levels or customer bills
E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers. (See Appendix D for a description of the derivation and use of this term in the LRIRIM test.)

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Where:

UACt = Utility avoided supply costs in year t
UICt = Utility increased supply costs in year t
RGt = Revenue gain from increased sales in year t
RLt = Revenue loss from reduced sales in year t
PRCt = Program Administrator program costs in year t
Et = System sales in kWh, kW or therms in year t or first year customers
UACat = Utility avoided supply costs for the alternate fuel in year t
Rlat = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B RIM and C RIM equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UCA_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC : E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC : D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t \sum_{i=1}^{I} (\Delta EN_{it} \times MC : E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC : D \times (K_{it} - 1))$$

Where:

[Only terms not previously defined are included here.]

ΔENit	=	Reduction in net energy use in costing period i in year t
ΔDNit	=	Reduction in net demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
MC:Dit	=	Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

RGt	=	BIt	* (net-to-gross ratio)
RLt	=	BRt	* (net-to-gross ratio)
Rlat	=	Abat	* (net-to-gross ratio)

Chapter 4

Total Resource Cost Test[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g.,, environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant.

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

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[6] This test was previously called the All Ratepayers Test

How the Results Can be Expressed

The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost. The net present value is the primary unit of measurement for this test. Secondary means of expressing TRC test results are a benefit-cost ratio and levelized costs. The Societal Test expressed in terms of net present value, a benefit-cost ratio, or levelized costs is also considered a secondary means of expressing results. Levelized costs as a unit of measurement are inapplicable for fuel substitution programs, since these programs represent the net change of alternative fuels which are measured in different physical units (e.g.,, kWh or therms). Levelized costs are also not applicable for load building programs.

Net present value (NPVTRC) is the discounted value of the net benefits to this test over a specified period of time. NPVTRC is a measure of the change in the total resource costs due to the program. A net present value above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based.

The benefit-cost ratio (BCRTRC) is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. It gives an indication of the rate of return of this program to the utility and its ratepayers. A benefit-cost ratio above one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.

The levelized cost is a measure of the total costs of the program in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the total costs of the program to the utility and its ratepayers on a per kilowatt, per kilowatt hour, or per therm basis levelized over the life of the program.

The Societal Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. More specifically, the Societal Test differs from the TRC Test in at least one of five ways. First, the Societal Test may use higher marginal costs than the TRC test if a utility faces marginal costs that are lower than other utilities in the state or than its out-of-state suppliers. Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources. Second, tax credits are treated as a transfer payment in the Societal Test, and thus are left out. Third, in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur. Fourth, a societal discount rate should be used[7]. Finally, Marginal costs used in the Societal Test would also contain externality costs of power generation not captured by the market system. An illustrative and

7 Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. Yet if a market discount rate is not used, comparisons with alternative investments are difficult to make.

by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.

3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line

4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
   a. Avoided costs of supply disruptions
   b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
   c. Marginally decreased System Operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
   d. Benefits to customers and the public of avoiding blackouts.

5. Non-energy benefits: Non-energy benefits might include a range of program-specific benefits such as saved water in energy-efficient washing machines or self generation units, reduced waste streams from an energy-efficient industrial process, etc.

6. Non-energy benefits for low income programs: The low income programs are social programs which have a separate list of benefits included in what is known as the 'low income public purpose test'. This test and the sepcific benefits associated with this test are outside the scope of this manual.

7. Benefits of fuel diversity include considerations of the risks of supply disruption, the effects of price volatility, and the avoided costs of risk exposure and risk management.

Strengths of the Total Resource Cost Test

The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand- and supply-side options.

Since this test treats incentives paid to participants and revenue shifts as transfer payments (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.

Weakness of the Total Resource Cost Test

The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.

In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.

Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options.

Formulas

The formulas for the net present value (NPV_{TRC})' the benefit-cost ratio (BCR_{TRC} and levelized costs are presented below:

NPVTRC = BTRC - CTRC
BCRTRC = BTRC /CTRC
LCTRC = LCRC / IMP

Where:

NPVTRC	=	Net present value of total costs of the resource
BCRTRC	=	Benefit-cost ratio of total costs of the resource
LCTRC	=	Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)
BTRC	=	Benefits of the program
CTRC	=	Costs of the program
LCRC	=	Total resource costs used for levelizing
IMP	=	Total discounted load impacts of the program
PCN	=	Net Participant Costs

The B_{TRC} C_{TRC} LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[\left(\sum_{i=1}^{n} \Delta EN_{it} \right) or \left(\Delta DN_{it} \text{ where } I = peak\ period \right) \right]}{(1+d)^{t-1}}$$

[All terms have been defined in previous chapters.]

The first summation in the BTRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Chapter 5

Program Administrator Cost Test

Definition

The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

Benefits and Costs

The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided supply costs for the energy-using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels.

The costs for the Program Administrator Cost Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). For fuel substitution programs, costs include the increased supply costs for the energy-using equipment chosen by the program participant only in the case of a combination utility, as above.

In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenue affects rates, it does not affect revenue requirements, which are defined as the difference between the net marginal energy and capacity costs avoided and program costs. Thus, if $NPV_{pa} > 0$ and $NPV_{RIM} < 0$, the administrator's overall total costs will decrease, although rates may increase because the sales base over which revenue requirements are spread has decreased.

How the Results Can be Expressed

The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.

Net present value (NPVpa) is the benefit of the program minus the administrator's costs, discounted over some specified period of time. A net present value above zero indicates that this demand-side program would decrease costs to the administrator and the utility.

The benefit-cost ratio (BCRpa) is the ratio of the total discounted benefits of a program to the total discounted costs for a specified time period. A benefit-cost ratio above one indicates that the program would benefit the combined administrator and utility's total cost situation.

The levelized cost is a measure of the costs of the program to the administrator in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the costs of the program to the administrator and the utility on per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

Strengths of the Program Administrator Cost Test

As with the Total Resource Cost test, the Program Administrator Cost test treats revenue shifts as transfer payments, meaning that test results are not complicated by the uncertainties associated with long-term rate projections and associated rate design assumptions. In contrast to the Total Resource Cost test, the Program Administrator Test includes only the portion of the participant's equipment costs that is paid for by the administrator in the form of an incentive. Therefore, for purposes of comparison, costs in the Program Administrator Cost Test are defined similarly to those supply-side projects which also do not include direct customer costs.

Weaknesses of the Program Administrator Cost Test

By defining device costs exclusively in terms of costs incurred by the administrator, the Program Administrator Cost test results reflect only a portion of the full costs of the resource.

The Program Administrator Cost Test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Formulas

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

$$NPVpa = Bpa - Cpa$$
$$BCRpa = Bpa/Cpa$$
$$LCpa = LCpa/IMP$$

Where:

NPVpa	Net present value of Program Administrator costs
BCRpa	Benefit-cost ratio of Program Administrator costs

LCpa	Levelized cost per unit of Program Administrator cost of the resource
Bpa	Benefits of the program
Cpa	Costs of the program
LCpc	Total Program Administrator costs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the Bpa equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Appendix A

Inputs to Equations and Documentation

A comprehensive review of procedures and sources for developing inputs is beyond the scope of this manual. It would also be inappropriate to attempt a complete standardization of techniques and procedures for developing inputs for such parameters as load impacts, marginal costs, or average rates. Nevertheless, a series of guidelines can help to establish acceptable procedures and improve the chances of obtaining reasonable levels of consistent and meaningful cost-effectiveness results. The following "rules" should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:

1. In the past, Marginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets. Such transactions could include spot market purchases as well as longer term bilateral contracts and the marginal costs should be estimated based on components for energy as well as demand and/or capacity costs as is typical for these contracts.

2. In the case of submittals in conjunction with a utility rate proceeding, average rates used in DSM program cost-effectiveness evaluations should be based on proposed rates. Otherwise, average rates should be based on current rate schedules. Evaluations based on alternative rate designs are encouraged.

3. Time-differentiated inputs for electric marginal energy and capacity costs, average energy rates, and demand charges, and electric load impacts should be used for (a) load management programs, (b) any conservation program that involves a financial incentive to the customer, and (c) any Fuel Substitution or Load Building program. Costing periods used should include, at a minimum, summer and winter, on-, and off-peak; further disaggregation is encouraged.

4. When program participation includes customers with different rate schedules, the average rate inputs should represent an average weighted by the estimated mix of participation or impacts. For General Rate Case proceedings it is likely that each major rate class within each program will be considered as program elements requiring separate cost-effectiveness analyses for each measure and each rate class within each program.

5. Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program.

6. For DSM programs or program elements that reduce electricity and natural gas consumption, costs and benefits from both fuels should be included.

7. The development and treatment of load impact estimates should distinguish between gross (i.e., impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand-side management programs, although in some instances there may be no difference between gross and net.

8. The use of sensitivity analysis, i.e. the calculation of cost-effectiveness test results using alternative input assumptions, is encouraged, particularly for the following programs: new programs, programs for which authorization to substantially change direction is being sought (e.g.,, termination, significant expansion), major programs which show marginal cost-effectiveness and/or particular sensitivity to highly uncertain input(s).

The use of many of these guidelines is illustrated with examples of program cost effectiveness contained in Appendix B.

Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP = BP - CP
NPVavp = (BP - CP) / P
BCRP = BP/CP
DPP = min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM	= (CRIM - BRIM) / E		
FRIRIM	= (CRIM - BRIM) / E	for t = 1	
ARIRIMt	= FRIRIM	for t = 1	
	= (CRIMt- BRIMt)/Et	for t=2,...	,N
NPVRIM	= BRIM — CRIM		
BCRRIM	= BRIM /CRIM		

Total Resource Cost Test

NPVTRC = BTRC - CTRC
BCRTRC = BTRC / CTRC
LCTRC = LCRC / IMP

Program Administrator Cost Test

NPVpa = Bpa - Cpa
BCRpa = Bpa / Cpa
LCpa = LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \sum_{t=1}^{n} \frac{\left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat	=	Avoided bill reductions on bill from alternate fuel in year t
AC:Dit	=	Rate charged for demand in costing period i in year t
AC:Eit	=	Rate charged for energy in costing period i in year t
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp	=	Benefit-cost ratio to participants
BCRRIM	=	Benefit-cost ratio for rate levels
BCRTRC	=	Benefit-cost ratio of total costs of the resource
BCRpa	=	Benefit-cost ratio of program administrator and utility costs
BIt	=	Bill increases in year t
Bj	=	Cumulative benefits to participants in year j
Bp	=	Benefit to participants
BRIM	=	Benefits to rate levels or customer bills
BRt	=	Bill reductions in year t
BTRC	=	Benefits of the program
Bpa	=	Benefits of the program
Cj	=	Cumulative costs to participants in year i

Cp	= Costs to participants
CRIM	= Costs to rate levels or customer bills
CTRC	= Costs of the program
Cpa	= Costs of the program
D	= discount rate
ΔDgit	= Reduction in gross billing demand in costing period i in year t
ΔDnit	= Reduction in net demand in costing period i in year t
DPp	= Discounted payback in years
E	= Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	= Reduction in gross energy use in costing period i in year t
ΔEnit	= Reduction in net energy use in costing period i in year t
Et	= System sales in kWh, kW or therms in year t or first year customers
FRIRIM	= First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	= Total discounted load impacts of the program
INCt	= Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are > cumulative costs.
Kit	= 1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	= Total resource costs used for levelizing
LCTRC	= Levelized cost per unit of the total cost of the resource
LCPA	= Total Program Administrator costs used for levelizing
Lcpa	= Levelized cost per unit of program administrator cost of the resource
LRIRIM	= Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	= Marginal cost of demand in costing period i in year t
MC:Eit	= Marginal cost of energy in costing period i in year t
NPVavp	= Net present value to the average participant
NPVP	= Net present value to all participants
NPVRIM	= Net present value levels
NPVTRC	= Net present value of total costs of the resource
NPVpa	= Net present value of program administrator costs
OBIt	= Other bill increases (i.e., customer charges, standby rates)
OBRt	= Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	= Number of program participants
PACat	= Participant avoided costs in year t for alternate fuel devices

PCt = Participant costs in year t to include:

- Initial capital costs, including sales tax
- Ongoing operation and maintenance costs
- Removal costs, less salvage value
- Value of the customer's time in arranging for installation, if significant

PRCt = Program Administrator program costs in year t
PCN = Net Participant Costs
RGt = Revenue gain from increased sales in year t
RLat = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt = Revenue loss from reduced sales in year t
TCt = Tax credits in year t
UACat = Utility avoided supply costs for the alternate fuel in year t
UACt = Utility avoided supply costs in year t
PAt = Program Administrator costs in year t
UICt = Utility increased supply costs in year t

Appendix C.

Derivation of Rim Lifecycle Revenue Impact Formula

Most of the formulas in the manual are either self-explanatory or are explained in the text. This appendix provides additional explanation for a few specific areas where the algebra was considered to be too cumbersome to include in the text.

Rate Impact Measure

The Ratepayer Impact Measure lifecycle revenue impact test (LRIRIM) is assumed to be the one-time increase or decrease in rates that will re-equate the present valued stream of revenues and stream of revenue requirements over the life of the program.

Rates are designed to equate long-term revenues with long-term costs or revenue requirements. The implementation of a demand-side program can disrupt this equality by changing one of the assumptions upon which it is based: the sales forecast. Demand-side programs by definition change sales. This expected difference between the long-term revenues and revenue requirements is calculated in the NPVRIM The amount which present valued revenues are below present valued revenue requirements equals NPVRIM

The LRIRIM is the change in rates that creates a change in the revenue stream that, when present valued, equals the NPVRIM* If the utility raises (or lowers) its rates in the base year by the amount of the LRIRIM' revenues over the term of the program will again equal revenue requirements. (The other assumed changes in rates, implied in the escalation of the rate values, are considered to remain in effect.)

Thus, the formula for the LRIRIM is derived from the following equality where the present value change in revenues due to the rate increase or decrease is set equal to the NPVRIM or the revenue change caused by the program.

$$-NPV_{RIM} = \sum_{t=1}^{N} \frac{LRI_{RIM} \times E_t}{(1+d)^{t-1}}$$

Since the LRI_{RIM} term does not have a time subscript, it can be removed from the summation, and the formula is then:

$$-NPV_{RIM} = LRI_{RIM} \times \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Rearranging terms, we then get:

$$LRI_{RIM} = -NPV_{RIM} \Big/ \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Thus,

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$